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REGULATORY IMPACT ANALYSIS FOR THE FINAL SECTION 126 PETITION RULE

Prepared by

Office of Air Quality Planning and Standards
Office of Atmospheric Programs
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AFS - AIRS Facility System
AIRS - Aerometric Information Retrieval System
ANPR - Advanced Notice of Proposed Rulemaking
b_{ext} - Total Atmospheric Light Extinction Coefficient
BACT - Best Available Control Technology
BEIS - Biogenic Emissions Inventory System
CAA - Clean Air Act
CAAA - Clean Air Act Amendments of 1990
CAPMS - Criteria Air Pollutant Modeling System
CASAC - Clean Air Scientific Advisory Committee
CASTNet - Clean Air Status and Trends Network
CB - Chronic Bronchitis
CO - Carbon Dioxide
COI - Cost of Illness
COPD - Chronic Obstructive Pulmonary Disease
C-R - Concentration-Response
CRDM - Climatalogical Regional Dispersion Model
CV - Contingent Valuation
dv - Deciview
ECOS - Environmental Council of States
EGUs - Electricity Generating Units
EO - Executive Order
EPA - Environmental Protection Agency
FIP - Federal Implementation Plan
H^+ - Hydrogen Ion
H_2O_2- Hydrogen Peroxide
HNO_3 - Nitric Acid
hr - Hour
IMPROVE - Interagency Monitoring for Protection of Visual Environments
IPM - Integrated Planning Model
Kg/ha - Kilograms Per Hectare
km^2 - Square Kilometer
kWh - Kilowatt Hour
LAER - Lowest Achievable Emissions Rates
lb - Pound
LDs - Loss Days
LRS - Lower Respiratory Symptoms
MCL - Maximum Contaminant Level
mills/kWh - Mills Per Kilowatt Hour
MM4 - Mesoscale Model, version 4

mmBtu - Millions of British Thermal Units
Mm- Megameter
MOU - Memorandum of Understanding
MRAD - Minor Restricted Activity Days
MRRAD - Minor Respiratory Restricted Activity Days
MW - Megawatts
MWh - Megawatt Hours
MWTP - Marginal Willingness to Pay
NAA - Nonattainment Area
NAAQS - National Ambient Air Quality Standards
NAPAP - National Acid Precipitation Assessment Program
NCLAN - National Crop Loss Assessment Network
NET - National Emission Trends
NH_3 - Ammonia
NLEV - National Low Emission Vehicle
NMSCs - Nonmelanoma Skin Cancers
NOAA - National Oceanic and Atmospheric Administration
NOx - Oxides of Nitrogen
NO_3 - Nitrate
NPR - Notice of Proposed Rulemaking
NPS - Non-Point Source
NSA - Nitrate, Sulfate, and Ammonium Components
NSPS - New Source Performance Standards
NSR - New Source Review
O_3 - Ozone
OMB - Office of Management and Budget
OMS - Office of Mobile Sources
O&M - Operation and Maintenance
OTAG - Ozone Transport Assessment Group
OTC - Ozone Transport Commission
OTR - Ozone Transport Region
PM - Particulate Matter
ppm - Parts Per Million
PRA - Paperwork Reduction Act of 1995
PSD - Prevention of Significant Deterioration
RIA - Regulatory Impact Analysis
RACT- Reasonably Available Control Technology
RFA - Regulatory Flexibility Act
RMF - Regional Model Farm

SAB - Science Advisory Board
SBA - Small Business Administration

SBREFA - Small Business Regulatory Enforcement Fairness Act of 1996
SNPR - Supplemental Notice of Proposed Rulemaking
SO_2 - Sulfur Dioxide
SO_4^{2-} - Sulfate Ion
SOA - Secondary Organic Aerosols
S-R - Source-Receptor
TAMM - Timber Assessment Market Model
tpd - Tons Per Day
tpy - Tons Per Year
TSP - Total Suspended Particulates
$\mu g/m^3$ - Micrograms Per Meter Cubed
UAM-V - Urban Airshed Model - Variable Scale
UMRA - Unfunded Mandates Reform Act
URS - Upper Respiratory Symptoms
USDA - United States Department of Agriculture
UV-B - Ultraviolet-B Radiation
VOCs - Volatile Organic Compounds
WLDs - Work Loss Days
WTP - Willingness to Pay

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EXECUTIVE SUMMARY

This document presents a Regulatory Impact Analysis (RIA) for the final Section 126 rule, which addresses regional transport issues related to ozone attainment. This rule requires certain States to take action to reduce emissions of nitrogen oxides (NOx) that contribute to nonattainment of ozone standards in downwind States. The final action under CAA Section 126 responds to petitions filed with EPA by eight Northeastern States requesting that EPA provide relief from emissions sources in several upwind States that may be contributing to ozone nonattainment in the petitioning States. Pursuant to Executive Order 12866, this RIA presents the potential costs, benefits, and economic impacts of these rulemakings.

In this final rulemaking, EPA is setting ozone season NOx budgets for sources that are in the 12 States and the District of Columbia which are named in the Section 126 petitions. The final set of sources that EPA is affecting with this rule include large electricity generating units, industrial boilers and combustion turbines. Table ES-1 lists the major regulatory alternatives that EPA considered for each of the above sectors and the emission reductions achieved by each. The shaded areas in the table show the options that EPA selected based largely on the Agency's determination (as explained in the preamble to this rulemaking) that the ozone season NOx controls for a sector were highly cost-effective and could be reasonably implemented in the near future. For all units affected by this rule, the Agency estimates the costs and emissions changes based on an emissions cap-and-trade program.

Table ES-1
2007 Ozone Season NOx Emission Reductions for Selected Combinations of Electricity Generating Units and Non-Electricity Generating Source Regulatory Alternatives [a]
(thousands of NOx Tons)

Regulatory Alternatives		Electricity Generating Units			
		0.25 lb/mm BTU NOx Trading	**0.20 lb/mm BTU NOx Trading**	**0.15 lb/mm BTU NOx Trading**	**0.12 lb/mm BTU NOx Trading**
Non-Electricity Generating Sources	**40% Control**	411	525	638	706
	50% Control	422	536	649	717
	60% Control	432	546	**659**	727
	70% Control	444	558	671	739

[a] Emissions reductions are shown in parentheses.

The remainder of this Executive Summary focuses only on the final regulatory alternative. The RIA chapters on cost and cost-effectiveness present results for all regulatory options. Due to time constraints the benefits analysis only presents results for the final regulatory alternative.

Presentation of results of this analysis

In its NOx SIP Call RIA, EPA presented the results of its analyses in 1990 dollars. Since that time, EPA's Office of Air and Radiation has revised the base year which it uses for its economic analyses. The RIA for the Office of Mobile Sources proposed Tier 2 rule presents results in 1997 dollars. Therefore, to allow readers easy comparison of the costs, cost effectiveness, and benefits to both the NOx SIP Call and this more recent economic analysis, EPA is presenting the summary results in both 1990 and 1997 dollars. There is no change in the regulatory option selected or overall cost benefit comparison as a result of moving to using 1997 dollars as the base year. Note that in the proposed Section 126 analysis an average ozone season cost-effectiveness of $2,000 per ton in 1990 dollars was indicated as the upper limit under the Agency's framework for highly cost-effective NOx emission reductions. When using 1997 dollars as the base year for comparison, the equivalent average ozone season cost-effectiveness is $2,460 per ton. The only difference between these two numbers is that the 1997 figure accounts for inflation between 1990 and 1997.

As noted in previous RIAs, in order to save time and resources, EPA has traditionally selected a representative year for estimating the annual costs and benefits for a rule. For the Section 126 and NOx SIP Call RIAs, we selected 2007, representing full implementation of the NOx controls to meet the mandated NOx caps. As explained in more detail in Chapter 9, selection of 2007 as the analytical year for the benefits analysis resulted in SO_2 emissions and air quality results that are not representative of the expected change in air quality for most years when the rule is in effect as a result of an assumption in the model. This assumption includes the expected switch by many utilities in the final Section 126 region to new, lower cost turbine technology in 2008 and beyond. This leads to a model result of greater allowance withdrawals (and thus higher levels of SO_2 emissions) in 2007 than for other years. As a result, EPA has constructed a proxy for a "representative year" (in terms of SO_2 emissions) by zeroing out all changes in sulfates, both positive and negative, in calculating the benefits of this rulemaking. As explained in Chapter 11, EPA believes that the "representative year" scenario is a closer approximation to the expected annual benefits of the final Section 126 rule, and will thus be the only scenario that is carried over into the summary comparison of benefits and costs. However, both the Integrated Cost Chapter (Chapter 9) and the Benefits Chapter (Chapter 11) will include results showing the impact of two other scenarios which show the range of effects of changes in SO_2 emissions: a 2007 scenario where SO_2 emissions are increasing and a 2004 scenario where SO_2 emissions are decreasing.

Costs and Cost-effectiveness

Table ES-2 summarizes EPA estimates of the costs and cost-effectiveness for the regulatory approach that EPA selected as the basis for the Section 126 NOx budgets. The table indicate the estimates of direct control costs for sources including costs associated with emissions monitoring and reporting. The table also includes the total administrative costs to State governments and EPA. In EPA's analysis to support this rule, the Agency has shown that for the electric power industry and large industrial boilers, a single trading program across the control region can provide a similar reduction to what direct command-and-control requirements would accomplish, but do the job at lower cost.

Table ES-2
Estimate of Total Annual Costs and Cost effectiveness in 2007 of the EPA's Selected Approach to the Section 126 Petitions

Total Annual Cost (Millions 1990$)	Average Ozone Season Cost-Effectiveness (1990$ per ozone season ton)	Total Annual Cost (Millions 1997$)	Average Ozone Season Cost-Effectiveness (1997$ per ozone season ton)
$951	$1,443	$1,146	$1,776

Economic Impacts

EPA considered what the economic impacts of the Section 126 rule for electricity generating units. Electricity prices could potentially rise in the final Section 126 region by as much as 1.6 percent in 2007, if the power industry is pricing its power on the basis of marginal costs in a fully competitive environment. The price increase will be less, if these assumptions regarding the nature of the competitive environment do not hold. There will be more new electric generation capacity built in response to the rule than will retire early (there will be little generation capacity that closes). On net, EPA expects this regulation to create more new jobs (from pollution control operations and increased natural gas use) than it reduces (due to a small decline in forecasted coal demand).

EPA examined the potential effect of the final Section 126 regulation on small entities that meet the Small Business Administration's definition of "small." The Agency adopted several ways of minimizing potential impacts on small entities for this rulemaking. Of the 379 small entities (both EGU and non-EGU) in the final Section 126 region, only 88 are affected by the Section 126 rule, and only 16 have compliance costs in excess of 1% of total revenues.

Benefits

Table ES-3 lists the anticipated health and welfare benefits categories that are reasonably associated with this rule specifying those for which sufficient quantitative information exists to permit benefit calculations. Because of the inability to monetize some existing categories, some categories are not included in the calculation of monetized benefits. The magnitude of the unquantified benefits associated with omitted categories, such as damage to ecosystems or damage to industrial equipment and national monuments, is not known. However, to the extent that unquantified benefits exceed unquantified disbenefits, the estimated benefits presented will be an underestimate of actual benefits.

The adoption of a value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economic and public policy analysis community within and outside the Administration. In response to the sensitivity on this issue, we provide estimates reflecting two alternative approaches. The first approach -- supported by some in the above community and preferred by EPA -- uses a Value of a Statistical Life (VSL) approach developed for the Clean Air Act Section 812 benefit-cost studies. This VSL estimate of $5.9 million (1997$) was derived from a set of 26 studies identified by EPA using criteria established in Viscusi (1992), as those most appropriate for environmental policy analysis applications.

An alternative, age-adjusted approach is preferred by some others in the above community both within and outside the Administration. This approach was also developed for the Section 812 studies and addresses concerns with applying the VSL estimate –reflecting a valuation derived mostly from labor market studies involving healthy working-age manual laborers– to PM-related mortality risks that are primarily associated with older populations and those with impaired health status. This alternative approach leads to an estimate of the value of a statistical life year (VSLY), which is derived directly from the VSL estimate. It differs only in incorporating an explicit assumption about the number of life years saved and an implicit assumption that the valuation of each life year is not affected by age.[1] The mean VSLY is $360,000 (1997$); combining this number with a mean life expectancy of 14 years yields an age-adjusted VSL of $3.6 million (1997$).

Both approaches are imperfect, and raise difficult methodological issues which are discussed in depth in the recently published Section 812 Prospective Study, the draft EPA Economic Guidelines, and the peer-review commentaries prepared in support of each of these documents. For example, both methodologies embed assumptions (explicit or implicit) about which there is little or no definitive scientific guidance. In particular, both methods adopt the assumption that the risk versus dollars trade-offs revealed by available labor market studies are

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[1] Specifically, the VSLY estimate is calculated by amortizing the $5.9 million mean VSL estimate over the 35 years of life expectancy associated with subjects in the labor market studies. The resulting estimate, using a 5 percent discount rate, is $360,000 per life-year saved in 1997 dollars. This annual average value of a life-year is then multiplied times the number of years of remaining life expectancy for the affected population (in the case of PM-related premature mortality, the average number of $ life-years saved is 14.

applicable to the risk versus dollar trade-offs the general population would make in an air pollution context.

EPA currently prefers the VSL approach because, essentially, the method reflects the direct, application of what EPA considers to be the most reliable estimates for valuation of premature mortality available in the current economic literature. While there are several differences between the labor market studies EPA uses to derive a VSL estimate and the particulate matter air pollution context addressed here, those differences in the affected populations and the nature of the risks imply both upward and downward adjustments. For example, adjusting for age differences may imply the need to adjust the $5.9 million VSL downward as would adjusting for health differences, but the involuntary nature of air pollution-related risks and the lower level of risk-aversion of the manual laborers in the labor market studies may imply the need for upward adjustments. In the absence of a comprehensive and balanced set of adjustment factors, EPA believes it is reasonable to continue to use the $5.9 million value while acknowledging the significant limitations and uncertainties in the available literature. Furthermore, EPA prefers not to draw distinctions in the monetary value assigned to the lives saved even if they differ in age, health status, socioeconomic status, gender or other characteristic of the adult population.

Those who favor the alternative, age-adjusted approach (i.e. the VSLY approach) emphasize that the value of a statistical life is not a single number relevant for all situations. Indeed, the VSL estimate of $5.9 million (1997 dollars) is itself the central tendency of a number of estimates of the VSL for some rather narrowly defined populations. When there are significant differences between the population affected by a particular health risk and the populations used in the labor market studies - as is the case here - they prefer to adjust the VSL estimate to reflect those differences. While acknowledging that the VSLY approach provides an admittedly crude adjustment (for age though not for other possible differences between the populations) they point out it has the advantage of yielding an estimate that is not presumptively biased. Proponents of adjusting for age differences using the VSLY approach fully concur that enormous uncertainty remains on both sides of this estimate - upwards as well as downwards - and that the populations differ in ways other than age (and therefore life expectancy). But rather than waiting for all relevant questions to be answered, they prefer a process of refining estimates by incorporating new information and evidence as it becomes available.

The VSL approach –the approach EPA prefers – yields a monetized benefit estimate of $1.2 billion. The alternative VSLY, age-adjusted approach yields total monetized benefits of $0.7 billion. Table ES-4 shows the estimated avoided incidences and monetized benefits resulting from implementation of the final Section 126 rule using EPA's preferred approach. The estimates of benefits for the final Section 126 rule using the two alternative approaches for premature mortality valuation are presented in Table ES-5. As discussed in Chapter 11, the benefits in any particular year may be greater or less than the values. However, for a typical year, the benefits are likely to be close to these values in Table ES-4.

Table ES-3.
Human Health and Welfare Effects of Ozone and Particulate Matter

Pollutant	Primary Quantified and Monetized Effects	Alternative Quantified and/or Monetized Effects	Unquantified Effects
Ozone Health	Chronic asthma[a] Minor restricted activity days and acute respiratory symptoms Hospital admissions - respiratory and cardiovascular Emergency room visits for asthma		Premature mortality[b] Increased airway responsiveness to stimuli Inflammation in the lung Chronic respiratory damage Premature aging of the lungs Acute inflammation and respiratory cell damage Increased susceptibility to respiratory infection Non-asthma respiratory emergency room visits Reduction in screening of UV-b radiation
Ozone Welfare	Decreased worker productivity Decreased yields for commercial crops		Decreased yields for commercial forests Decreased yields for fruits and vegetables Decreased yields for non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Damage to ecosystem functions

Pollutant	Primary Quantified and Monetized Effects	Alternative Quantified and/or Monetized Effects	Unquantified Effects
PM Health	Premature mortality Bronchitis - chronic and acute Hospital admissions - respiratory and cardiovascular Emergency room visits for asthma Lower and upper respiratory illness Shortness of breath Minor restricted activity days and acute respiratory symptoms Work loss days		Infant mortality Low birth weight Changes in pulmonary function Chronic respiratory diseases other than chronic bronchitis Morphological changes Altered host defense mechanisms Cancer Non-asthma respiratory emergency room visits
PM Welfare	Visibility in Southeastern Class I areas	Visibility in Northeastern and Midwestern Class I areas Visibility in Eastern residential areas Household soiling	
Nitrogen and Sulfate Deposition Welfare		Costs of nitrogen controls to reduce eutrophication in selected eastern estuaries	Impacts of acidic sulfate and nitrate deposition on commercial forests Impacts of acidic deposition to commercial freshwater fishing Impacts of acidic deposition to recreation in terrestrial ecosystems Reduced existence values for currently healthy ecosystems Impacts of nitrogen deposition on commercial fishing, agriculture, and forests Impacts of nitrogen deposition on recreation in estuarine ecosystems

[a] While no causal mechanism has been identified linking new incidences of chronic asthma to ozone exposure, a recent epidemiological study shows a statistical association between long-term exposure to ozone and incidences of chronic asthma in some non-smoking men, but not in women.

[b] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope, et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.

Table ES-4
Estimated Annual Quantified and Monetized Benefits of the Final Section 126 Rule in 2007 for the "Representative Year" SO_2 Emissions Banking Scenario

Endpoint	Pollutant	Avoided Incidence[b] (cases/year)	Monetary Benefits[c] (millions 1997$)
Premature mortality[a,f] (adults, 30 and over)	PM	200	$1,090
Chronic asthma (adult males, 27 and over)	Ozone	U_2	B_2
Chronic bronchitis	PM	100	$30
Hospital Admissions from Respiratory Causes	Ozone and PM	50+U_3	$1+$B_3$
Hospital Admissions from Cardiovascular Causes	Ozone and PM	20+U_4	<$1+$B_4$
Emergency Room Visits for Asthma	Ozone and PM	40+U_5	<$1+$B_5$
Acute bronchitis (children, 8-12)	PM	400	<$1
Lower respiratory symptoms (LRS) (children, 7-14)	PM	3,800	<$1
Upper respiratory symptoms (URS) (asthmatic children, 9-11)	PM	3,900	<$1
Shortness of breath (African American asthmatics, 7-12)	PM	1,000	<$1
Work loss days (WLD) (adults, 18-65)	PM	29,900	$3
Minor restricted activity days (MRAD)/Acute respiratory symptoms	Ozone and PM	159,700+U_7	$10+$B_7$
Decreased worker productivity	Ozone	—	B_8
Other health effects	Ozone and PM	U_1+U_9	B_1+B_9
Recreational (Class I Area) visibility	PM and Gases	—	$40
Residential visibility	PM and Gases	—	B_{10}
Household soiling damage	PM	—	B_{11}
Materials damage	PM	—	B_{12}
Nitrogen Deposition	Nitrogen	—	B_{13}
Agricultural crop damage	Ozone	—	B_{15}
Commercial forest damage	Ozone	—	B_{16}
Other welfare effects	Ozone and PM	—	B_{14}+B_{17}
Monetized Total[f]			**$1,180+B**

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] Incidences are rounded to the nearest 100.
[c] The U_I are the incidences for the unquantified category i.
[d] Dollar values are rounded to the nearest 10.
[e] **B** is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_{17}$.
[f] These estimates are based on the EPA preferred approach for valuing reductions in premature mortality, the VSL approach. This approach and an alternative, age-adjusted approach – the VSLY approach – are discussed more fully in section 11.9.

Table ES-5.
Final Section 126 Rule "Representative Year" SO_2 Emissions Banking Scenario: 2007 Monetized Benefits Estimates for Alternative Premature Mortality Valuation Approaches (Billions of 1997 dollars)

Premature Mortality Valuation Approach	**PM Mortality Benefits**	**Total PM Benefits**
Value of statistical life (VSL) ($5.9 million per life saved)[a]	$1.1	$1.2 + **B**
Value of statistical life-years (VSLY) ($360,000 per life-year saved)[a, b]	$0.6	$0.7 + **B**

[a] Premature mortality estimates are determined assuming a 5 year distributed lag, which applies 25 percent of the incidence in year 1 and 2, and then 16.7 percent of the incidence in years 3, 4, and 5.
[b] The VSLY estimate is calculated by amortizing the $5.9 million mean VSL estimate over the 35 years of life expectancy associated with subjects in the labor market studies used to obtain the VSL estimate. The resulting estimate, using a 5 percent discount rate, is $360,000 per life-year saved in 1997 dollars. This approach is discussed more fully in section 11.9 above.

Comparison of Costs and Monetized Benefits

Benefit-cost analysis provides a systematic framework for assessing and comparing such regulatory alternatives. According to economic theory, the efficient alternative maximizes net benefits to society (i.e., social benefits minus social costs). However, there are practical limitations for the comparison of benefits to costs in this analysis. As pointed out above, there are several categories of benefits from this rulemaking which EPA is not able to monetize. Nonetheless, if one is mindful of these limitations, the relative magnitude of the benefit-cost comparison presented here can be useful information.

Using EPA's preferred approach for monetizing reductions in PM-related premature mortality – the VSL approach – total monetized benefits (ozone plus PM) of the final Section 126 rule are projected to be around **$1.4 billion (1997$).** Any comparison of benefits and costs for this rule will provide limited information, given the incomplete estimate of benefits. However, even with the limited set of benefit categories we were able to monetize, monetized net benefits using EPA's preferred method for valuing avoided incidences of premature mortality are approximately **$0.3 billion (1997$).** Using an alternative, age-adjusted approach – the VSLY approach – total monetized benefits are projected to be around **$0.9 billion (1997$)**. Monetized net benefits using this approach are approximately **$-0.2 billion (1997$)**. Tables ES-6 and ES-7 summarize the costs, benefits and net benefits for the two alternative valuation approaches.

Table ES-6
2007 "Representative Year" Estimated Annual Monetized Costs, Benefits, and Net Benefits for the Section 126 Rule: EPA Preferred Estimates Using the Value of Statistical Lives Saved Approach to Value Reductions in Premature Mortality[a,b]

	Million 1990$	Million 1997$
Compliance costs	$1,000	$1,200
Monetized PM-related benefits[b,e]	$1,000 + B_{PM}	$1,200 + B_{PM}
Monetized Ozone-related benefits[b,d]	$200 + B_{Ozone}	$200 + B_{Ozone}
Monetized net benefits[c,d,e]	$200 + B_{PM}+B_{Ozone}	$200 + B_{PM}+B_{Ozone}

[a] For this summary, all costs and benefits are rounded to the nearest $100 million to simplify the comparison. Thus, figures presented in this table may not exactly equal benefit and cost numbers presented in other tables or subsequent chapters.
[b] B_{PM} represents the sum of all the unmonetized PM-related benefits, B_{Ozone} represents the sum of all the unmonetized ozone-related benefits.
[c] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table ES-3.
[d] Ozone benefits are only roughly estimated here due to time constraints. Modeled ozone benefits will appear in subsequent volumes of this analysis in January 2000. See Benefits chapter for explanation of how benefits are calculated.
[c] These estimates are based on the EPA preferred approach for valuing reductions in premature mortality, the VSL approach. This approach and an alternative, age-adjusted approach – the VSLY approach – are discussed more fully in section 11.9 of Chapter 11.

Table ES-7
2007 "Representative Year" Estimated Annual Monetized Costs, Benefits, and Net Benefits for the Section 126 Rule: EPA Preferred Estimates Using the Value of Statistical Life Years Saved Approach to Value Reductions in Premature Mortality[a,b]

	Million 1990$	Million 1997$
Compliance costs	$1,000	$1,200
Monetized PM-related benefits[b,e]	$600 + B_{PM}	$700 + B_{PM}
Monetized Ozone-related benefits[b,d]	$200 + B_{Ozone}	$200 + B_{Ozone}
Monetized net benefits[c,d,e]	$-200 + B_{PM}+B_{Ozone}	$-300 + B_{PM}+B_{Ozone}

[a] For this summary, all costs and benefits are rounded to the nearest $100 million to simplify the comparison. Thus, figures presented in this table may not exactly equal benefit and cost numbers presented in other tables or subsequent chapters.
[b] B_{PM} represents the sum of all the unmonetized PM-related benefits, B_{Ozone} represents the sum of all the unmonetized ozone-related benefits.
[c] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table ES-3.
[d] Ozone benefits are only roughly estimated here due to time constraints. Modeled ozone benefits will appear in subsequent volumes of this analysis in January 2000. See Benefits chapter for explanation of how benefits are calculated.
[c] The VSLY estimate is calculated by amortizing the $5.9 million mean VSL estimate over the 35 years of life expectancy associated with subjects in the labor market studies used to obtain the VSL estimate. The resulting estimate, using a 5 percent discount rate, is $360,000 per life-year saved in 1997 dollars. This approach is discussed more fully in section 11.9 of Chapter 11.

In addition to the monetized benefits listed in Tables ES-6 and ES-7, the Section 126 rule may result in significant improvements in visibility in urban and suburban residential areas, and reductions in loadings of nitrogen to sensitivity estuaries, potentially helping state and local governments reach target reduction goals for important estuaries including the Chesapeake Bay, the Albemarle-Pamlico Sound, and Long Island Sound. The Section 126 rule will help reduce loadings in these estuaries by up to 22 percent of stated reduction goals.

Direct Comparison to NOx SIP Call

To assist the reader, EPA has pulled the appropriate information from the NOx SIP Call RIA to compare to this analysis. It is important to note that EPA's approach to estimating some benefit categories has changed to reflect the latest and best external scientific advice on appropriate methodologies and assumptions since the NOx SIP Call benefits analysis was completed. Thus, the benefit numbers in Table ES-8 below are adjusted from the NOx SIP Call RIA to reflect the benefits assumptions and methodology used in this analysis. Note that there are some categories of monetized benefits (e.g. commercial forestry related benefits) included in the NOx SIP call estimate that were not included in the Section 126 benefits due to time constraints.

Table ES-8
Comparison of NOx SIP Call and Section 126 Rulemaking

	Affected Jurisdictions	2007 Ozone Season NOx Emission Reductions (thousands of NOx Tons)	Average Ozone Season Cost-Effectiveness (1990$ per ozone season ton)	Total Annual Cost (Millions 1990$)	Monetary Benefits[a] (Millions 1990$)	Net Monetary Benefits[a] (Millions 1990$)
NOx SIP Call	23	1161	$1,500	$1,700	$2,500+B[b]	$800+B[b]
Section 126	13	659	$1,511	$1,000	$1,200+B[b]	$200+B[b]

[a] In the NOx SIP Call RIA benefits were $4,200 million and net benefits were $2,500.
[b] B represents the sum of all the unmonetized benefits

Differences between the two sets of data are thought to result from the following: 1) the number of tons reduced is roughly 40% less for the Section 126 rule, 2) for the Section 126 rule, NOx emission reductions are occurring in less populated areas than the NOx SIP Call which covered a broader territory and more population centers.

Limitations

Cost-benefit analysis provides a valuable framework for organizing and evaluating information on the effects of environmental programs. When used properly, cost-benefit analysis helps illuminate important potential effects of alternative policies and helps set priorities for closing information gaps and reducing uncertainty. However, not all relevant costs and benefits can be captured in any analysis. Executive Order 12866 clearly indicates that unquantifiable or nonmonetizable categories of both costs and benefits should not be ignored. There are many important unquantified and unmonetized costs and benefits associated with reductions in NOx emissions, including many health and welfare effects. Potential benefit categories that have not been quantified and monetized are listed in Table ES-3.

Several specific limitations deserve to be mentioned:

- The state of atmospheric modeling is not sufficiently advanced to provide a workable "one atmosphere" model capable of characterizing ground-level pollutant exposure for all pollutants of interest (e.g., ozone, particulate matter, carbon monoxide, nitrogen deposition, etc). Therefore, EPA must employ several different pollutant models to characterize the effects of alternative policies on relevant pollutants. Also, not all atmospheric models have been widely validated against actual ambient data. In particular, since a broad-scale monitoring network does not yet exist for fine particulate matter ($PM_{2.5}$), atmospheric models designed to capture the effects of alternative policies on $PM_{2.5}$ are not fully validated. Additionally, shortcomings exist in the data that are available to perform these analyses. While containing identifiable shortcomings and uncertainties, EPA believes the models and assumptions used in the analysis are reasonable based on the available evidence.

- Evaluating the potential costs of a rulemaking provides one framework for policy makers and the public to assess policy alternatives. Not all the potential costs can be captured in any analysis. However, EPA is generally able to estimate reasonably well the costs of pollution controls based on today's control technology and assess the important impacts when it has sufficient information for its analysis. EPA compiled through the OTAG process and from many other sources, including public comments, sufficient information for this rulemaking.

- There is the uncertainty regarding future costs that exists due to the flexibility that occurs under the emissions cap-and-trade program. The analysis that EPA has done to date has been fairly conservative in considering the electric power industry and large industrial boilers and combustion turbines operating separately under their own trading programs. In reality, they should enter the same trading pool and there should be greater efficiency and lower costs that result.

- Another dimension adding to the uncertainty of this analysis is time. We use 2007 as the base year for analysis. In the case of air pollution control, 8 years is a long time over which to carry assumptions. Pollution control technology has advanced considerably in the last 10 years and can be expected to continue to advance in the future. Yet there is no clear way to model this advance for use in this analysis. In addition, there is no clear way to predict future meteorological conditions, or the growth in source-level emissions over time. Again, EPA believes that the assumptions to capture these elements are reasonable based on the available evidence.

- Qualitative and more detailed discussions of the above and other uncertainties and limitations are included in the analysis. Where information and data exist, quantitative characterizations of these uncertainties are included. However, data limitations prevent an overall quantitative estimate of the uncertainty associated with final estimates. Nevertheless, the reader should keep these uncertainties and limitations in mind when reviewing and interpreting the results.

Chapter 1. Introduction and Background

1.1 Introduction

This document presents a Regulatory Impact Analysis for the final Section 126 rule, which addresses regional transport issues related to ozone attainment. This rule requires certain States to take action to reduce emissions of nitrogen oxides (NOx) that contribute to nonattainment of ozone standards in downwind States[1]. The final action under CAA Section 126 responds to petitions filed with EPA by eight Northeastern States requesting that EPA provide relief from emissions sources in several upwind States that may be contributing to ozone nonattainment in the petitioning States.

The Clean Air Act (CAA) requires States to demonstrate attainment of the National Ambient Air Quality Standards (NAAQS) for ozone. Many States have found it difficult to demonstrate attainment of the 1-hour ozone NAAQS due to the widespread regional transport of ozone and its precursors, NOx and volatile organic compounds (VOCs). The Ozone Transport Assessment Group (OTAG) was established in 1995 to undertake an assessment of the regional transport problem in the Eastern half of the United States. OTAG was a collaborative process among 37 affected States, the District of Columbia, the U.S. Environmental Protection Agency (EPA), and interested members of the public, including environmental groups and industry representatives.

OTAG concluded that regional reductions in NOx emissions are needed to reduce the transport of ozone and its precursors. OTAG recommended that major sources of NOx emissions (utility and other stationary sources) be controlled under State NOx budgets, and also recommended development of an emissions trading program.

After a review of OTAG's analysis, findings, and recommendations, EPA proposed a rule to limit summer season NOx emissions in a group of States that the Agency believes are significant contributors to ozone in downwind areas.[2] In a November 7, 1997 Notice of Proposed Rulemaking (NPR), EPA made a determination that transport of ozone from certain States in the OTAG region[3] made a significant contribution to nonattainment, or interfered with the maintenance of attainment, with the ozone NAAQS in downwind States (FR, 1997a). EPA proposed a summer season NOx budget (in tons of NOx) for each of these States. These States

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[1] Ground level (or tropospheric) ozone is an air pollutant that forms when its two primary components, oxides of nitrogen and volatile organic compounds , combine in the presence of certain meteorological conditions. Ozone is associated with a variety of adverse effects both to human health and to the environment. For more information on these adverse effects refer to Chapter 11 of this RIA.

[2] NOx emissions reductions were proposed for 22 States and the District of Columbia.

[3] The OTAG region consists of 37 States east of 104^{o} W longitude.

will be required to amend their State Implementation Plans (SIPs) through a call-in procedure established in Section 110 of the Clean Air Act Amendments of 1990 (CAAA). In a May 1998 Supplemental Notice of Proposed Rulemaking (SNPR), EPA made technical corrections to the State NOx budgets, and developed a proposed trading rule to provide for emissions trading (FR, 1998a). The SNPR also included an analysis of the air quality impacts of the proposed rule. The State NOx emissions budgets, trading rule, and related provisions are now being promulgated as a final rule.

A technical background support document prepared for the November 7, 1997 NPR estimated costs and emissions reductions associated with an assumed strategy that States might take to achieving the proposed budgets (EPA, 1997a). In an analysis supporting the April 1998 SNPR (EPA, 1998a), updates were made to reflect technical corrections to the population of sources and growth estimates on which the State-specific budgets were based and to assess the effects of the proposed trading system. These analyses were further updated for the September 1998 NFR for the NOx SIP call, and were recalculated for a smaller number of States representing those jurisdictions covered in the final Section 126 rule (EPA, 1999b).

Additionally, this chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The results presented in this chapter take into account changes that have been made to the NOx emissions inventory. These changes are the result of the inventory correction notices issued on January 13, 199 and May 14,1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy resulting from EPA's stay of the findings based on the 8-hour ozone NAAQS.

This document provides the supporting Regulatory Impact Analysis (RIA) for the final Section 126 rule. This analysis expands and updates the previous analyses to reflect the provisions of the final rule and to provide analysis of the potential benefits, costs, economic impacts, and air quality impacts associated with this rule.

The remaining sections of this chapter address the following topics:

1.2 Relevant requirements of the Clean Air Act;

1.3 Relationship between the NOx SIP call, and section 126 actions;

1.4 Statement of need for the NOx SIP call;

1.5 Administrative requirements addressed by this RIA;

1.6 Structure of the RIA and organization of this document; and

1.7 References for Chapter 1.

1.2 The Clean Air Act

The 1970 Clean Air Act Amendments required EPA to issue, periodically review, and, if necessary, revise, NAAQS for ubiquitous air pollutants (Sections 108 and 109). States are required to submit SIPs to attain those NAAQS and Section 110 of the CAA lists minimum requirements that SIPs must meet. Congress anticipated that all areas would attain the NAAQS by 1975. In 1977, the CAA was amended to provide additional time for areas to reach the NAAQS and included the requirement that States reach the NAAQS for ozone by 1982 or 1987. In addition, the 1977 amendments included provisions that required SIPs to consider adverse downwind effects and allowed downwind States to petition for tighter controls on upwind States that contribute to their NAAQS nonattainment status.

In 1990, the Clean Air Act was again amended . This section outlines requirements of the 1990 Clean Air Act Amendments (CAAA) related to NOx reductions and the NOx SIP call. The discussion includes the ozone and NOx requirements and a review of the guidelines for new or advanced air emissions control technologies.

1.2.1 Ozone Requirements

The CAAA included provisions designed to address the continued nonattainment of the existing ozone NAAQS, specified requirements that would apply if EPA revised the existing standard, and addressed transport of air pollutants across State boundaries.

In 1991 and 1992, areas not in attainment with the 1-hour ozone NAAQS were placed in one of five classifications, based on the degree of nonattainment. Requirements for moving toward attainment, including definitions of “major source” for VOCs and NOx, attainment dates and new source offset ratios, were established for each of the five classifications. Within an area known as the Northeast Ozone Transport Region (OTR), all sources emitting 50 tons or more of ozone forming pollutants a year are defined as “major sources”. This definition of major sources for the OTR is independent of the area’s current attainment status. If a source is defined as major, it is subject to specific emission limitations.

Since passage of the 1990 CAAA, EPA has revised the NAAQS for ozone (EPA, 1997). EPA is required to review the NAAQS at least every five years to determine whether, based on new research, revisions to the standards are necessary to continue to protect human health and the environment. As a result of the most recent review, EPA revised the NAAQS for both particulate matter and ozone (EPA, 1997). The previous ambient air quality standard for ozone was 0.12 ppm based on 1-hour averaging of monitoring results. The revised standard was set at 0.08 ppm based on an 8- hour averaging period. The 1-hr standard remains in effect until EPA determines that a given area has air quality meeting its 1-hour standard. This is necessary to ensure continued progress in those areas and a smooth transition between the two standards.

On July 16, 1997, President Clinton issued a directive to EPA on the implementation strategy for the new ozone and particulate matter (PM) NAAQS. The goal of the implementation strategy is to provide flexible, common-sense, and cost-effective means for communities and businesses to comply with the new standard. EPA has issued proposed guidance for public comment on implementation of the revised standards (August 24, 1998, 63 FR 45060). Additional guidance was proposed in October 1998. The August and October guidance were combined and issued as one document in December 1998. The implementation strategy includes:

> *Endorsement of a Regional Approach*: Citing EPA's work with the OTAG, the implementation strategy notes that ozone needs to be addressed as a regional problem. The Directive indicates that, based on OTAG recommendations, EPA will propose a rule to provide a flexible, common-sense, and cost effective means for communities and businesses to comply with the new standards. The strategy states that EPA will encourage and assist the States to develop a regional emissions cap-and-trade system, modeled on the current acid rain program, as a way to achieve reduction in NOx emissions at lower cost.
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> *Cost-Effective Implementation Strategies*: EPA will encourage States to design strategies for both the PM and ozone standards that focus on getting low cost reductions and that limit the cost of control to under $10,000 per ton for all sources. EPA will encourage market-based strategies to lower the cost of attainment and stimulate technological innovation. EPA issued draft Economic Incentive Program guidance for public comment on September 15, 1999 (EPA, 1999).

1.2.2 NOx Control and Ozone Reduction

To address the CAAA provisions regarding continued nonattainment of the existing ozone NAAQS, EPA's post-1994 attainment strategy guidance for the 1-hour ozone standard called for continued emissions reductions within ozone nonattainment areas together with a national assessment of the ozone transport phenomenon. Recognizing that no individual state or jurisdiction can effectively assess or resolve all of the issues relevant to ozone transport, the Environmental Council of States (ECOS) formed a national work group to address ozone pollution.[4] OTAG was established to assist states east of the Mississippi River to attain federal ozone standards and to develop regional strategies to address regional transport problems.[5] The multi-state, multi-stakeholder OTAG process included input from State and local governments, industry, environmental groups, and the Federal government. The stated goal of OTAG was to:

> Identify and recommend a strategy to reduce transported ozone and its precursors which, in combination with other measures, will enable attainment and maintenance of the

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[4] ECOS is a national organization of environmental commissioners with members from the 50 States and territories.

[5] Information on OTAG and copies of documents produces by the group can be accessed on-line at http://www.epa.gov/ttn/otag.

national ambient ozone standard in the OTAG region. A number of criteria will be used to select the strategy including, but not limited to, cost effectiveness, feasibility, and impacts on ozone levels (OTAG, 1995).

OTAG's work included development of a comprehensive base-year (1990) emissions inventory for use in all OTAG analyses. The inventory contained information provided by the States and reviewed by OTAG for point, area, and mobile sources. State-specific growth factors were used to project emissions for the years 1999 and 2007, which represent the CAAA attainment dates for certain nonattainment areas. Baseline 2007 emissions were also adjusted to reflect the effect of various controls required under existing regulatory programs or expected from future programs.

OTAG then conducted modeling of NOx and ozone across the OTAG region for several scenarios using geographic and atmospheric models:

Strategy Modeling. OTAG Strategy Modeling was performed in several phases, and included analysis of more than 25 emission control strategies. OTAG found that domain-wide emissions of NOx in the 2007 baseline are approximately 12 percent lower than 1990 and emissions of VOC are approximately 20 percent lower. Thus, existing CAA programs are expected to produce a reduction in ozone concentrations in many nonattainment areas. However, the analysis shows that some areas currently in nonattainment will likely remain so in the future and that new 8-hour nonattainment and/or maintenance problem areas may develop as a result of economic growth in some areas (OTAG, 1997).

Geographic Modeling. OTAG conducted geographic modeling to isolate the effects of NOx reductions on specific subregions. Among other results, OTAG found that a regional strategy focusing on NOx reductions across a broad portion of the region will help mitigate the ozone problem in many areas of the East. Further, a regional NOx emissions reduction strategy coupled with local NOx and/or VOC reductions may be needed to achieve attainment and maintenance of the NAAQS in the region.

This analysis conducted by OTAG (OTAG, 1997), as well as EPA's analyses in support of the new ozone NAAQS (EPA, 1997b), demonstrated the important role NOx emissions reductions play in the reduction of ozone levels. The extensive air quality modeling performed by OTAG indicated that both ozone and NOx can be transported long distances, up to 500 miles. While reductions in either NOx and VOCs may reduce ozone in localized urban areas, only NOx reductions would result in lower ozone levels across the region. The OTAG analyses showed a correlation between the magnitude and location of NOx reductions and the magnitude of reductions in ozone levels in downwind areas. OTAG, therefore, reached the following conclusion:

> Regional NOx reductions are effective in producing ozone benefits; the more NOx reduced, the greater the benefit. Ozone benefits are greatest where emission

reductions are made and diminish with distance. Elevated and low level NOx reductions are both effective (OTAG, 1997, pp. 51-52).

Based on evidence of the relationship between NOx emissions and regional ozone levels, OTAG recommended that a range of NOx controls be applied in certain areas of the OTAG region. A wide variety of sources are responsible for NOx emissions, including electricity generating units, other (non-utility) stationary sources, area sources, non-road mobile sources, and highway vehicle sources. OTAG did not suggest any one "correct" approach to reducing major source NOx emissions. However, OTAG developed a number of specific recommendations for EPA pertinent to the NOx SIP call, including the following:[6]

- OTAG-related controls should be implemented in the "fine grid" states.[7]

- The range of utility NOx controls should fall between Clean Air Act controls and the less stringent of 85% reduction from the 1990 rate (lb/mmBtu) or 0.15 lbs. of NOx /mmBtu summer heat input.

- The stringency of controls for individual large non-utility point sources should be established in a manner equitably with utility controls, and RACT should be considered for individual medium non-utility point sources where appropriate.[8] OTAG recommended that EPA calculate statewide NOx tonnage budgets based on a specified relationship between control levels for coal-fired power plants and control targets (emission reduction percentages) for large and medium non-utility point sources.

- OTAG stated that market-based approaches are recognized as having a number of benefits in relation to traditional command and control regulations, and that States have the option to select market systems that best suit their needs. They described two basic approaches that States might use to implement NOx emissions market systems, and recommended that a joint State/EPA Workgroup be formed to develop design features and implementation provisions for market systems that States could select.

OTAG also made recommendations that EPA develop and adopt a variety of specific national regulations that were assumed for the modeling to result in reduced emissions of VOCs and/or NOx, and to reach closure on the Tier 2 Motor Vehicle Study.

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[6] Summaries of the OTAG findings and recommendations are provided in OTAG, 1997.

[7] The fine grid states include those modeled using UAM-V at a grid resolution of 12 km^2. All other areas constitute the coarse grid which is modeled at a grid resolution of 36 km^2. Coarse grid states are Florida, Louisiana, Texas, Arkansas, Oklahoma, Kansas, Nebraska, North Dakota, South Dakota, and Minnesota.

[8] OTAG provided specific definitions of large and medium point sources, for purposes of their recommendations.

The recommendations resulting from the extensive analysis and air quality modeling conducted by OTAG have played a major role in the design of the final Section 126 rule.

1.2.3 Title IV NOx Requirements

Title IV of the CAAA requires annual reductions in NOx emissions. The Acid Rain NOx Program under Title IV incorporates a two-phased strategy to reduce NOx emissions. In the first phase that began on January 1, 1996, certain Group 1 boilers (i.e., dry bottom wall-fired boilers and tangentially fired boilers) were required to comply with specific NOx emission limitations.[9] In the second phase, starting January 1, 2000, the remaining Group 1 boilers must comply with more stringent NOx emission limits.[10] Further, Group 2 boilers (i.e., wet bottom wall-fired boilers, cyclones, boilers using cell-burner technology, and vertically fired boilers) must comply with recently established emission limits.[11]

Compliance results for 1996 show that, from 1990 to 1996, the Phase I affected population's average NOx emission rate declined by 40 percent. Overall NOx emission reductions between 1990 and 1996 for the affected boilers totaled approximately 340,000 tons, i.e. a reduction of 33 percent (EPA, 1997c). In Phase II , about 1.17 million tons per year of NOx reductions are projected to result from the Acid Rain NOx Program requirements (EPA, 1996).

In developing State budgets for the final Section 126 rule, EPA took into consideration the NOx reductions committed to by Title IV NOx Program requirements.

1.2.4 New Source Performance Standards

The EPA promulgated a new source performance standard (NSPS) on fossil fuel fired utility and industrial boilers in September 1998, and subpart GG of Part 60 regulates NOx emissions from combustion turbines. The final standards revise the NOx emission limits for steam generating units in subpart Da (Electric Utility Steam Generating Units) and subpart Db (Industrial-Commercial-Institutional Steam Generating Units). Only those electricity generating units and industrial steam generating units for which construction, modification, or reconstruction

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[9] The affected dry-bottom wall-fired boilers must meet a limitation of 0.50 lbs of NOx per mmBtu averaged over the year, and tangentially fired boilers must achieve a limitation of 0.45 lbs of NOx per mmBtu, again averaged over the year (FR 1995).

[10] Annual averages of 0.46 lb/mmBtu for dry-bottom wall-fired boilers and 0.40 lb/mmBtu for tangentially fired boilers.

[11] The limits are 0.68 lb/mmBtu for cell burners, 0.86 lb/mmBtu for cyclones greater than 155 MWe, 0.84 lb/mmBtu for wet bottom boilers greater than 65 MWe, and 0.80 lb/mmBtu for vertically fired boilers (FR 1996a).

commenced after July 9, 1997 would be affected by these revisions (September 3, 1998, 63 FR 49442) .

The NOx emission limit in the final rule for newly constructed subpart Da units is 200 nanograms per joule (ng/J) [1.6 lb/megawatt-hour (MWh)] gross energy output regardless of fuel type. For existing sources that become subject to subpart Da through modification or reconstruction, the NOx emission limit is 65 ng/J (0.15 lb/million Btu heat input). For subpart Db units, the NOx emission limit being proposed is 87 ng/J (0.20 lb/million Btu) heat input from the combustion of natural gas, oil, coal, or a mixture containing any of these fossil fuels; however, for the low heat release rate units firing natural gas or distillate oil, the current NOx emission limit of 43 ng/J (0.10 lb/million Btu) heat input is unchanged (September 3, 1998, 63 FR 49442).

In developing the State budgets for the final Section 126 rule, EPA considered the potential NOx reductions attributable to this NSPS.

1.2.5 Reasonably Available Control Technology Requirements

In the 1977 amendments to the CAA Congress required that all SIPs for nonattainment areas contain reasonably available control measures (RACM) or reasonably available control technology (RACT). In the 1990 Amendments to the Act, Congress created RACT requirements specifically for ozone nonattainment areas under the 1-hour standard (see subpart 2 of part D of title I). Since 1977, EPA has defined RACT for ozone as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available, taking into account technological and economic feasibility. The EPA historically has interpreted the RACT requirement in ozone nonattainment areas to apply independent of a State's ability to demonstrate that an area will attain the ozone standard, with certain exceptions.

In the ozone-specific RACT requirement enacted in 1990, States were required to correct all existing deficiencies in RACT rules in marginal nonattainment areas to ensure the rules were adopted consistently on a national basis. In addition, all nonattainment areas classified moderate and above were required to adopt RACT for each source category for which EPA issued a Control Techniques Guideline (CTG). Over the years, EPA has issued CTG documents to assist the States in determining RACT for VOCs. Each CTG contains information on available air pollution control techniques and provides a "presumptive norm" for RACT for a specific source category. Finally, RACT for controlling NOx was also required in certain nonattainment areas classified moderate and above.

In developing the State budgets for the final Section 126 rule, EPA considered the potential NOx reductions resulting from RACT requirements.

1.2.6 Northeast Ozone Transport Region

Section 184 of the CAAA delineated a multi-state ozone transport region (OTR) in the Northeast and required specific additional NOx and VOC controls for all areas in this region (not only nonattainment areas). Section 184 also established the Ozone Transport Commission (OTC) for the purpose of assessing the degree of ozone transport in the OTR and recommending strategies to mitigate the interstate transport of pollution. The OTR consists of the States of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, parts of northern Virginia, and the District of Columbia. The OTC was first convened in 1991, and began analysis and evaluation of ozone reduction strategies for the region. It concluded that regional reductions of NOx emissions are particularly important in reducing ozone. The OTR States confirmed they would implement RACT on major stationary sources of NOx, and agreed to a phased approach for additional controls, beyond RACT, for power plants and other large fuel combustion sources.

This agreement, known as the OTC Memorandum of Understanding (MOU) for stationary source NOx controls was approved on September 27, 1994. All OTC States, except Virginia, are signatories to the OTC NOx MOU (OTC, 1994). The OTC NOx MOU establishes an emissions trading system to reduce the costs of compliance with the control requirements.

In developing State budgets for the final Section 126 rule, EPA considered the NOx reductions committed to by the OTR states in the OTC NOx MOU, along with the OTAG recommendations discussed above.

Chapter 2 of this report describes a number of regulatory alternatives that EPA considered in the development of this final rule.

1.3 Relationship Between NOx SIP Call and Section 126 Petitions

In conjunction with promulgation of the NOx SIP call, EPA has begun efforts to respond to petitions filed by eight northeastern States (FR, 1998b). These petitions were filed under section 126 of the CAA, which authorizes States to petition EPA to address air pollution transported from upwind States. The petitions request that EPA make a finding that NOx emissions from certain major stationary sources significantly contribute to ozone nonattainment problems in the petitioning States. If EPA makes such a finding, the Agency would be authorized to establish Federal emissions limits for these sources. The petitions recommend control levels for EPA to consider. In an April 30, 1998 Advanced Notice of Proposed Rulemaking (ANPR) (63 FR 24058), EPA presented a schedule for taking actions on the petitions, made a preliminary identification of upwind sources that may significantly contribute to 1-hour and 8-hour ozone nonattainment problems in the petitioning States (using information developed for the NOx SIP call NPR), and requested comment on legal and policy issues raised by section 126 of the CAA.

The Section 126 petition responses will directly impose regulatory requirements on emissions sources. EPA will regulate sources under the Section 126 petition actions with strategies that are modeled in this RIA.

1.3.1 Section 126 Findings Under the 1-Hour and 8-Hour Ozone Standard

Two rulings of the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) during 1999 affected EPA's rulemaking under Section 126. In one ruling, the court remanded the 8-hour NAAQS for ozone, which formed part of the underlying technical basis for certain of EPA's determinations under Section 126 (See American Trucking Ass'ns v. EPA No. 97-1441 and consolidated cases (D.C. Cir. May 14, 1999)). In a separate action, the D.C. Circuit Court granted a motion to stay the State Implementation Plan (SIP) submission deadlines established in the NOx SIP call (Michigan v. EPA, No. 98-1497 (D.C. Cir. May 25, 1999)) (order granting stay in part). On June 24, 1999, EPA proposed two changes to the April 30, 1999 Section 126 Notice of Final Rulemaking (NFR) to address issues raised by the rulings. EPA proposed to stay indefinitely the portion of the rule based on the 8-hour standard pending further developments in the NAAQS litigation. In addition, EPA proposed to remove the trigger mechanism for making findings that were based on the NOx SIP call deadlines and to instead make the findings in a final rule in November 1999. In a second final rulemaking on the eight petitions, EPA is staying the 8-hour portion of the rule and is making findings under the 1-hour standard. The findings affect large EGUs and large non-EGUs located in the following States: Delaware, District of Columbia, Indiana, Kentucky, Maryland, Michigan, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia.[12] The compliance deadline is May 1, 2003.

The EPA is also finalizing a Federal NOx Budget Trading Program for the source categories for which final findings are being made with respect to the eight petitions. The trading program is based on the application of a 0.15 lb/mmBtu NOx emission rate for large EGUs and a 60 percent reduction from uncontrolled emissions for large non-EGUs.

The final Section 126 actions will affected only a subset of the sources potentially affected by the broader NOx SIP call. Therefore, the benefits associated with the final Section 126 rule are likely to be smaller than for the final NOx SIP call.

[12] Only portions of Indiana, Kentucky, Michigan, and New York are affected.

1.4 Statement of Need for the Final Section 126 Rule

The following sections discuss the statutory authority and legislative requirements of the final Section 126 rule, health and welfare effects of NOx emissions, and the basis for the regulatory actions of the final Section 126 rule.

1.4.1 Statutory Authority and Legislative Requirements

Section 126 of the CAA authorizes a downwind State to petition EPA for a finding that any new (or modified) or existing major stationary source or group of stationary sources upwind of the State emits or would emit in violation of the prohibition of section 110 (a) (2) (D) (i) because their emissions contribute significantly to nonattainment, or interfere with maintenance, of a NAAQS in the State. If EPA makes the requested finding, the sources must shut down within three months from the finding unless EPA directly regulates the sources by establishing emissions limitations and a compliance schedule, extending no later than three years from the date of the finding, to eliminate the prohibited interstate transport of pollutants as expeditiously as possible. More details on this legal authorization can be found in sections 110 (a) (D) (2) (i) and 126 (c) of the CAA.

Section 110(a) (2) (D) provides that a SIP must contain provisions preventing its sources from contributing significantly to nonattainment or interfering with maintenance of the NAAQS in a downwind State. This section applies to all pollutants covered by NAAQS and all areas regardless of their attainment designation. Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet any CAA requirement, as well as being inadequate to mitigate interstate transport as described in Sections 184 and 176A. Such a finding would require States to submit a SIP revision to correct the inadequacy within a specified period of time.

1.5.2 Health and Welfare Effects of NOx Emissions[13]

NOx emissions contribute to the formation of ozone during the summer season. Ozone is a major component of smog and is harmful to both human health and the environment. Research has shown the following health effects of ozone:

- Exposure to ambient ozone concentrations has been linked to increased hospital admissions for respiratory ailments, such as asthma. Repeated exposure to ozone can make people more susceptible to respiratory infection and lung inflammation, and can aggravate preexisting respiratory diseases.

[13] A comprehensive discussion of health and environmental issues related to NOx appears in EPA, 1997d.

- Children are at risk for the effects of ozone because they are active outside during the summer months when ozone levels are at their highest. Adults who are outdoors and moderately active during the summer months are also at risk. These individuals can experience a reduction in lung function and an increase in respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion.

- Long-term exposures to ozone can cause repeated inflammation of the lung, impairment of lung defense mechanisms, and irreversible changes in lung structure, which could lead to premature aging of the lungs and/or chronic respiratory illnesses such as emphysema and chronic bronchitis.

- Several peer reviewed epidemiology studies recently published suggest a possible association between ozone exposure and mortality, though several other studies find no significant association.

Ozone has also been shown to adversely affect vegetation, including reductions in agricultural and commercial forest yields, reduced growth and decreased survivability of tree seedlings, and increased tree and plant susceptibility to disease, pests and other environmental stresses (EPA, 1996).

NOx emissions also contribute to fine PM formation(EPA, 1996). Exposure to airborne PM has a wide range of adverse health effects. The key health effects associated with PM include: 1) premature mortality; 2) aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions and emergency room visits, school absences, work loss days, and restricted activity days); 3) changes in lung function and increased respiratory symptoms; 4) changes to lung tissues and structure; 5) altered respiratory defense mechanisms; and 6) chronic bronchitis. Most of these effects have consistently been associated with ambient PM concentrations, which have been used as a measure of population exposure, in a number of community epidemiological studies. The mechanisms by which particles cause effects has been elucidated, but there is general agreement that the cardio-respiratory system is the major target of PM effects. Particulate matter also is associated with welfare effects, which include visibility impairment, soiling, and materials damage. These effects are addressed in the benefits chapter of the RIA.

Based on its review of the scientific evidence, EPA established standards for $PM_{2.5}$ and retained the standards for PM_{10}. The EPA revised the secondary (welfare-based) PM NAAQS by making them identical to the primary standards.

Finally, NOx emissions contribute to a wide range of health and environmental problems independent of their contribution to ozone or PM formation. Among these problems are acid deposition, nitrates in the drinking water, and nutrient loading in waterways, particularly in sensitive coastal estuaries where air deposition is a major portion of nitrogen loadings.

For further information on health and welfare effects from ozone formation, refer to Chapter 11 of this RIA.

1.4.3 Need for Regulatory Action

The existing and revised ambient air quality standards for ozone set levels necessary for the protection of human health and the environment. Under the CAA, attainment of these standards depends on the implementation of State-specific pollution control strategies contained in SIPs to reduce NOx and VOC emissions, in conjunction with EPA promulgation of national controls for some sources of pollution.

It is clear that, even with planned national measures in place, several States cannot bring existing nonattainment areas into compliance with the current ozone standard, or avoid the application of very costly local control measures, unless the transport of ozone from other upwind areas is reduced. Furthermore, many States will find it difficult to avoid nonattainment with the revised ozone NAAQS, or come into attainment with it in the future, unless mitigation of the ozone transport problem occurs. This dilemma has raised concerns over the fairness of downwind areas having to cope with the pollution coming from areas upwind. The current regulatory framework requires States to develop SIPs that demonstrate air quality improvements sufficient to reach specific attainment levels. States have no control over neighboring States' actions, and may be unable to meet their air quality goals due to pollutants transported across State lines. The contribution of upwind sources outside of nonattainment areas creates a dilemma for States seeking to reach air quality goals.

States could develop local ozone mitigation strategies to address the impact of transported ozone. However, local efforts could lead to undesirable outcomes. Some States might develop SIPs that do not achieve compliance in some serious and severe ozone nonattainment areas, because the States would deem local measures needed to achieve attainment as too draconian.

The final Section 126 rule is designed to mitigate these problems through a coordinated Federal and State effort to address regional ozone transport. This is a product of the interactoin between EPA and OTAG referred to earlier in this chapter. The final Section 126 rule will create a more effective, efficient and equitable approach for EPA and the States to promote attainment with the current ozone NAAQS.

1.5 Requirements for this Regulatory Impact Analysis

This section describes various legislative and executive requirements that govern the analytical requirements for Federal rulemakings, and describes how each analytical requirement is addressed in this RIA.

1.5.1 Executive Order 12866

Executive Order 12866, "Regulatory Planning and Review" (FR, 1993), requires EPA to provide the Office of Information and Regulatory Affairs of the Office of Management and Budget with an assessment of the costs and benefits of significant regulatory actions. A "significant regulatory action" is defined as "any regulatory action that is likely to result in a rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order" (FR, 1993).

For any such regulatory action, the Agency must provide a statement of the need for the proposed action, must examine alternative approaches, and estimate social benefits and costs.

EPA has determined that the NOx SIP call is not a significant regulatory action because no new regulatory requirements beyond those provided in the April 30, 1999 NFR will be imposed. However, this RIA has been prepared to provide updated benefits, costs, and economic impacts based on the latest NOx emissions inventory and scope of geographical coverage. This RIA provides the benefits information required by E.O. 12866 for a significant regulatory action. It also fulfills the associated cost and economic impact requirements.

1.5.2 Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996

The Regulatory Flexibility Act (RFA) of 1980 (PL 96-354) requires that agencies conduct a screening analysis to determine whether a regulation will have a significant impact on a substantial number of small entities, including small businesses, governments and organizations. If a regulation will have such an impact, agencies must prepare a Regulatory Flexibility Analysis, and comply with a number of procedural requirements to solicit and consider flexible regulatory options that minimize adverse economic impacts on small entities. The RFA's analytical and procedural requirements were strengthened by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996.

For reasons explained more fully in the Federal Register notice for the final Section 126 rule, it is EPA's position that the RFA as amended by SBREFA does apply to the Section 126 action. EPA has already prepared a Final Regulatory Flexibility Analysis (FRFA) for the April 30, 1999 NFR. EPA has examined the potential for small entity impacts in light of the latest Nox emissions inventory and new scope of geographic coverage.

The RFA and SBREFA require use of definitions of "small entities", including small businesses, governments and non-profits, published by the Small Business Administration (SBA).[14] Screening analyses of economic impacts presented in this RIA examine potential impacts on small entities.

The EPA estimates total number of potentially affected small entities in the Section 126 region that own one or more sources in the affected source categories under the narrower scope of the Section 126 requirements in 40 CFR 52.34 is approximately 379. The number of entities affected, presented by source category, is as follows:

Electric Generating Units - 80 small entities. This represents 45 percent of the potentially affected small entities in the final Section 126 region (179).

Industrial Boilers and/or Combustion Turbines - 8 small entities. This represents 4 percent of the potentially affected small entities owning these non-EGU sources in the final Section 126 region (200).

The total number of small entities that will be affected by the final Section 126 requirements under 40 CFR 52.34 is therefore 88, or 25 percent of small entities that own sources in the final Section 126 region that may be affected by this rule.

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[14] Where appropriate, agencies can propose and justify alternative definitions of "small entity." This RIA relies on the SBA definitions.

EPA has tried to reduce the impact of the final Section 126 rule on small entities. The EPA has reduced the applicability of regulatory requirements based on several factors including input from the SBREFA panel convened for the proposed Section 126 rule (63 FR 56292, October 21, 1998), considerations of overall cost-effectiveness, and administrative efficiency. The Panel recommended that EPA solicit comment on whether to allow electricity generating units to obtain a federally-enforceable NOx emission tonnage (e.g., 25 tons during the ozone season) and thereby obtain an exemption. Based on comments received, this option is incorporated in the final Section 126 regulations.

1.5.3 Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act (UMRA) of 1995 (PL 104-4) was enacted to focus attention on federal mandates that require other governments and private parties to expend resources without federal funding, to ensure that Congress considers those costs before imposing mandates, and to encourage federal financial assistance for intergovernmental mandates. The Act establishes a number of procedural requirements. The Congressional Budget Office is required to inform Congressional committees about the presence of federal mandates in legislation, and must estimate the total direct costs of mandates in a bill in any of the first five years of a mandate, if the total exceeds $50 million for intergovernmental mandates and $100 million for private-sector mandates.

Section 202 of UMRA directs agencies to provide a qualitative and quantitative assessment of the anticipated costs and benefits of a Federal mandate that results in annual expenditures of $100 million or more. The assessment should include costs and benefits to State, local, and tribal governments and the private sector, and identify any disproportionate budgetary impacts. Section 205 of the Act requires agencies to identify and consider alternatives, including the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

EPA has determined that UMRA does not affirmatively apply to this regulatory action. This RIA however, includes a cost analysis of administrative requirements for State and local governments associated with revising SIPs and collecting and reporting data to EPA. It also includes the compliance and administrative costs to emissions sources owned by government entities. In addition, EPA has prepared a detailed written statement consistent with the requirements of section 202 and section 205 of UMRA and placed that statement in the docket for this rulemaking.

1.5.4 Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (PRA) requires Federal agencies to be responsible and publicly accountable for reducing the burden of Federal paperwork on the public. EPA has submitted an Information Collection Request (ICR) to the Office of Management and Budget

(OMB) in compliance with the PRA. The ICR explains the need for additional information collection requirements and provides respondent burden estimates for additional paperwork requirements to State and local governments associated with the final 126 rule.

In the May 25 NFR, EPA relied upon an ICR prepared for the proposed Section 126 rule. For today's rule, EPA has updated the estimates contained in the ICR to account for the now narrower scope of the final Section 126 requirements in 40 CFR 52.34. These estimates of administrative burden costs are contained in the docket for this action and are summarized below.

Repondents/Affected Entities: Large fossil fuel boilers, turbines and combined cycle units that are subject to the current scope of the final Section 126 rule of 40 CFR 52.34.

Number of Respondents: 720

Frequency of Response:
- Emissions reports quarterly for some units, twice during ozone season for others
- Test notifications and allowance transfers on an infrequent basis
- Compliance certifications on an annual basis

Estimated Annual Hour Burden per Respondent: 80

Estimated Annual Cost per Respondent: $4,167

Estimated Total Annual Hour Burden: 57,600

Estimated Total Annualized Cost: $3,400,000

Note that these are average estimates for the first three years of the program. EPA estimates lower costs in the first two years of the program because fewer units will be participating at that time. The units that will participate at that time are those applying for early reduction credits. EPA also estimates that the highest compliance costs will occur in 2002, when a majority of the units that have to install and certify new monitors to comply with the program will do so. EPA believes the year 2003 will be more representative of the actual ongoing costs of the program. At that time EPA estimates a burden of 179 hours per source and a cost of $27,670 per source.

Burden means the total time, effort, and financial resources expended by persons to generate, maintain, retain, and disclose or provide information to or for a federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, processing, maintaining and disclosing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and nor is a person required, to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR Chapter 15.

1.5.5 Executive Order 12898

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," requires federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. Disproportionate adverse impacts on these populations should be avoided. According to EPA guidance, agencies are to assess whether minority or low-income populations face risk or a rate of exposure to hazards that is significant (as defined by the National Environmental Policy Act) and that "appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or other appropriate comparison group." (EPA, 1996b) This guidance outlines EPA's Environmental Justice Strategy and discusses environmental justice issues, concerns, and goals identified by EPA and environmental justice advocates in relation to regulatory actions.

In conjunction with the final NOx SIP call rulemaking, the Agency has conducted a general analysis of the potential changes in ozone and PM levels that may be experienced by minority and low-income populations as a result of the NOx SIP call; these findings are presented in the RIA for the Final NOx SIP call. The findings include population-weighted exposure characterizations for projected ozone concentrations and PM concentrations. The population data includes census-derived subdivisions for whites and non-whites, and for low-income groups. Although the final Section 126 rule is narrower in scope than the NOx SIP call, the NOx SIP call analysis indicates the potential types of effects that minority and low-income populations could experience as a result of this rule.

The final Section 126 rule is expected to provide health and welfare benefits to eastern U.S. populations, regardless of race or income. Chapter 11 of this RIA presents information on the changes in potential ozone and PM exposure for white and non-white populations and low income populations, and compares these relative changes to the general population.

1.5.6 Health Risks for Children

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks," directs Federal agencies developing health and safety standards to include an evaluation of the health and safety effects of the regulations on children. Regulatory actions covered under the Executive Order include rulemakings that are economically significant under Executive Order 12866, and that concern an environmental health risk or safety risk that the agency has reason to believe may disproportionately affect children. EPA has developed internal guidelines for implementing the E.O. 13045. (EPA, 1998b)

This rule is not subject to Executive Order 13045, because it is not economically significant under E.O. 12866 and the Agency does not have reason to believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children.

Nonetheless, we have evaluated the environmental health and safety effects of the affected pollutants on children, and found no effects from changes in ozone and PM levels resulting from an application of these regulatory requirements that are particular to children that are not found in other age groups. In conjunction with the final NOx SIP call rulemaking, the Agency has conducted a general analysis of the potential changes in ozone and PM levels experienced by children as a result of the NOx SIP call; these findings are presented in the RIA for the Final NOx SIP call. The findings include population-weighted exposure characterizations for projected 2007 ozone and PM concentrations. The population data includes a census-derived subdivision for the under age 18 group. Although the final Section 126 rule is narrower in scope than the NOx SIP call, the NOx SIP call analysis indicates the potential types of effects that children could experience as a result of this rule.

The final Section 126 rule is not a "significant economic action," because no new regulatory requirements are associated with this rule. Both Nox and ozone formed by Nox are known to affect the health of children and other sensitive populations, which were addressed in the development of the new ozone NAAQS. However, compliance with the final Section 126 rule is not expected to have a disproportionate impact on children. Chapter 11 of this RIA presents information on the changes in potential ozone and PM exposure for persons under the age of 18.

1.5.7 Executive Order 13132

Executive Order 13132, entitled Federalism (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications. "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, imposes substantial direct compliance costs, or that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

If EPA complies by consulting States and local governments, Executive Order 13132 requires EPA to provide to OMB, in a separately identified section of the preamble to the rule, a federalism summary impact statement (FSIS). The FSIS must include a description of the extent of EPA's prior consultation with State and local officials, a summary of the nature of their concerns and the agency's position supporting the need to issue the regulation, and a statement of the extent to which the concerns of State and local officials have been met. Also, when EPA transmits a draft final rule with federalism implications to OMB for review pursuant to Executive Order 12866, EPA must include a certification from the Agency's Federalism Official stating that EPA has met the requirements of Executive Order 13132 in a meaningful and timely manner.

The final Section 126 rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. As discussed above, this rule imposes no new requirements that impose compliance burdens beyond those already included in the May 25 NFR. Thus, the requirements of section 6 of the Executive Order do not apply to this rule. Nevertheless, EPA did consult with State and local officials throughout the Section 126 rulemaking (see 64 FR 28253-28254; 63 FR 57362-57363). Fundamentally, the Section 126 rulemaking is EPA's response to State petitions for EPA action. In addition, States were extensively involved with OTAG, which was established to undertake an assessment of the regional transport problem in the eastern half of the United States and to develop solutions. The OTAG process included representatives of both upwind and downwind States. In the Section 126 rulemaking, EPA has acted on Section 126 petitions submitted by States that were involved in the OTAG process. All eight submitted petitions rely, in part, on the OTAG analyses for technical justification.

1.5.8 Executive Order 13084

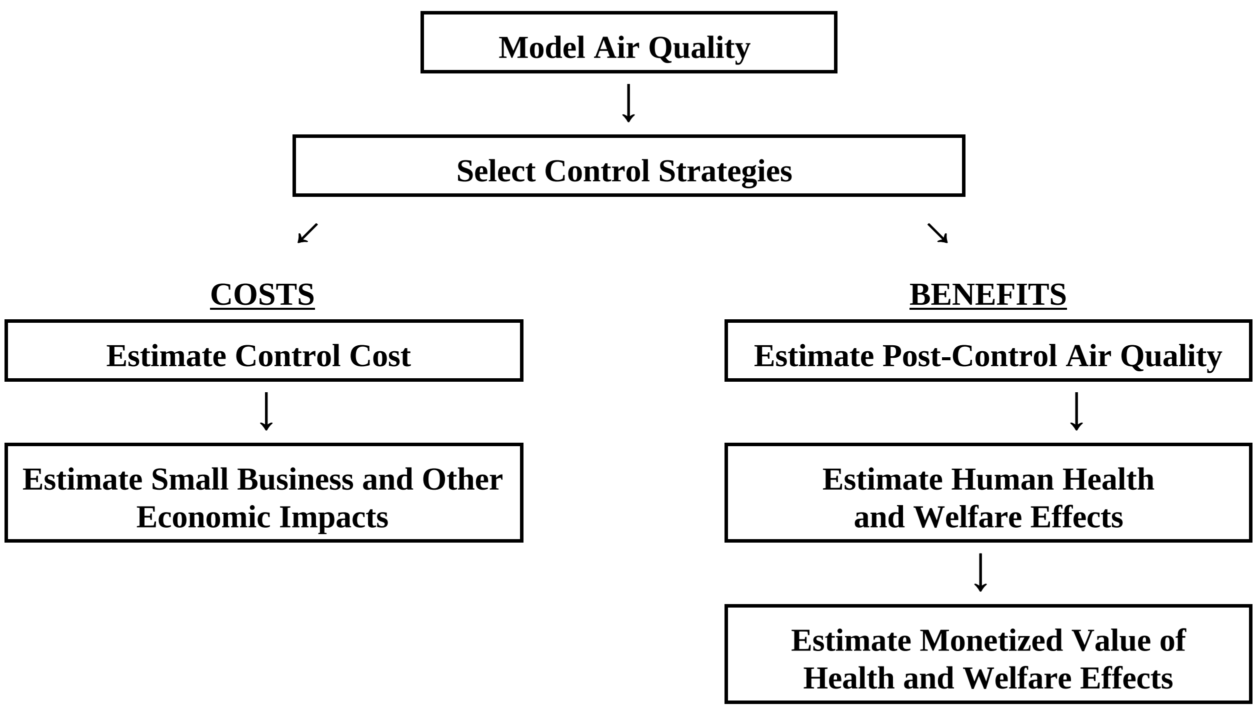
Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, or that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting these governments, Executive Order 13084 requires EPA to provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments "to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities."

The final Section 126 rule does not significantly or uniquely affect the communities of Indian tribal governments. As discussed above, this rule imposes no new requirements that impose compliance burdens beyond those already required by the May 25 NFR. Moreover, the final Section 126 rule will not impose substantial direct compliance costs on such communities. The EPA is not aware of sources located on tribal lands that could be subject to the requirements in 40 CFR 52.34. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply.

1.6 Structure and Organization of the Regulatory Impact Analysis

The potential costs, economic impacts and benefits have been estimated for this rulemaking. The flow chart in Figure 1-1 summarizes the analytical steps taken in developing the results presented in this RIA.

Figure 1-1
Flowchart of Analytical Steps



The assessment of costs, economic impacts, and benefits consists of multiple analytical components, dependent upon emissions and air quality modeling. In order to estimate baseline air quality in the year 2007, emission inventories are developed for 1995 and then projected to 2007, based upon estimated national growth in industry earnings and other factors. Current CAAA-mandated controls (e.g., Title I reasonably available control measures, Title II mobile source controls, Title III air toxics controls, Title IV acid rain sulfur dioxide (SO_2) controls) are applied to these emissions to take account of emission reductions that should be achieved in 2007 as a result of implementation of the current PM and ozone requirements. These 2007 CAA emissions in turn are input to several air quality models that relate emission sources to area-specific pollutant concentrations. This modeled air quality is used as the base against which several alternative control options are measured and cost estimates developed. Given the estimated costs of the alternative regulatory control options, the potential economic impacts costs on potentially affected industry sectors are assessed. Potential health and welfare benefits are also estimated from modeled changes in air quality as a result of control strategies applied in the cost analysis. Finally, benefits and costs are compared.

The analyses for the RIA have been constructed such that costs are estimated incremental to those derived from the effects of implementing the CAAA in the year 2007. These analyses provide a “snapshot” of potential costs of this rulemaking in the context of implementation of CAA requirements between now and 2007 and the air quality effects that derive from economic and population growth.

Analysis of costs, changes in emissions, and economic impacts is conducted separately for two groups of sources: electricity generating units and other stationary sources. The Integrated Planning Model (IPM) allows analysis of trading and industry-level adjustments for electricity generating unit sources. Industrial boilers and combustion turbines are analyzed separately, using assumptions about baseline conditions and control costs that are generally consistent with the IPM modeling assumptions used for electricity generating units.

Predicted changes in emissions due to the additional controls for electricity generating units and other stationary sources are then combined to estimate changes in air quality and to calculate the benefits of the final Section 126 rule. The estimation of benefits from environmental regulations poses special challenges. These include the difficulty of quantifying the expected change in the incidence of health, welfare, and environmental endpoints of concern, and the difficulty of assigning monetized values to these endpoints. A result of the difficulty of quantifying these endpoints of concern is that many categories of potential benefits have not been monetized at all. This RIA has adopted the approach of presenting a “primary estimate” of monetized benefits to reflect these uncertainties by selecting alternative values for each of several key assumptions. Taken together, these alternative sets of assumptions define the range for the monetized benefits categories.

The remainder of the RIA is organized in the following chapters and appendices:

- Chapter 2 presents a discussion of the regulatory alternatives analyzed in this report;

- Chapter 3 presents the profile of regulated entities;

- Chapter 4 describes the methodology for estimating impacts for the electric power industry;
- Chapter 5 describes the methodology for estimating impacts for non-EGUs;
- Chapter 6 presents the results of the analyses for EGUs;
- Chapter 7 presents the results of the analyses for non-EGUs;
- Chapter 8 details the impacts on government entities;
- Chapter 9 integrates impact analysis results for EGUs and non-EGUs;
- Chapter 10 discusses air quality impacts and other inputs to the benefits analyses;
- Chapter 11 describes the benefits of regional Nox reductions;
- Chapter 12 details the benefits-cost comparison.

The appendices for this RIA will include additional information on the costs and benefits for EGU and non-EGU entities.

1.7 References

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Chapter 2. Regulatory Alternatives And Emissions Impacts

This chapter explains the various regulatory alternatives considered in the final Section 126 rulemaking. Section 2.1 provides background on the elements considered that differentiate the alternatives. Section 2.2 lists the references for the chapter.

Additionally, this chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The results presented in this chapter take into account changes that have been made to the NOx emissions inventory. These changes are the result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy resulting from EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS.

2.1 Elements Considered in Developing Regulatory Alternatives

EPA's final Section 126 rule sets summer NOx emissions budgets for 12 States and the District of Columbia based on findings by the Agency that various States significantly contribute to other States' nonattainment of the existing ozone standard (1-hour). Chapter 1, Section 1.3.1, provides a current status of both the 1-hour and 8-hour ozone standards based on recent court rulings. EPA relied heavily on its estimation of the NOx reductions that the electric power industry and non-electricity generating sources could cost-effectively provide when setting the State budgets. Other factors, such as the feasibility of implementing controls in a reasonable time frame, also influenced the Agency's final decisions on implementation dates. To estimate the cost-effectiveness of controls for various sources, the Agency considered several ways that controls could be implemented in the final Section 126 region. However, States can place controls on their sources of NOx emissions different from those EPA used in the budget setting process, if they can show that their control strategy will provide the same level of NOx reduction in the final Section 126 region.

This section describes the elements that make up the various regulatory alternatives considered for this analysis. Some elements of the rule remain the same for all the options considered. Other elements are considered in varying combinations, including stringency of controls, geographic scope, affected sources and design of the trading system. For all options analyzed, the timing of regulatory requirements was also considered, as this issue is critical in terms of feasibility of compliance and attainment of both the pre-existing and the revised ozone standards.

2.1.1 Type of Control

EPA had to decide on the types of regulatory approaches that it wanted States to consider in their efforts to lower NOx emissions from various source categories. EPA used those approaches when it estimated the cost-effectiveness of ozone season NOx controls at various levels for different types of sources. OTAG recommended the Agency consider controls that allow for emissions trading, rather than traditional command-and-control regulation. OTAG's analysis of trading programs showed considerable savings from this type of approach for the electric power industry (OTAG, 1997).

In its regulatory analysis for the final NOx SIP call, EPA demonstrated the potential savings that could result from a NOx emissions trading program (EPA, 1998a). EPA's analysis showed that in 2005, a command-and-control program for the electric power industry would cost about 30 percent more than a trading program in the NOx SIP call region. For this reason, the Agency has focused heavily on developing regulatory approaches States can use collectively that are based on allowance-based NOx emissions trading. It was also clear from OTAG analysis and EPA's own work that further savings and flexibility could be gained from allowing banking as part of a trading program. EPA's regulatory analyses has also considered including banking options in the Federal NOx Budget Trading Program (EPA, 1999b).

2.1.2 Geographic Scope

After considering OTAG's recommendations and other relevant information, EPA identified parts of 12 States plus the District of Columbia (i.e., 13 jurisdictions) as significantly contributing to nonattainment of, or interfering with maintenance of, the 1-hour ozone air quality standard in a downwind State. The final Section 126 region consists of whole or parts of Delaware, District of Columbia, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The petitions filed with EPA only name parts of Indiana, Michigan, Kentucky, and New York while naming the whole of the other jurisdictions.

The final Section 126 rule reflects State NOx budgets that are developed using the same region-wide stringency targets and region-wide analyses of cost-effectiveness for all 13 jurisdictions.

2.1.3 Affected Sources

EPA has developed State budgets based on the effects of additional controls only on source categories named in the petitions submitted by States under Section 126 of the Clean Air Act (CAA). These sources include: (1) electricity generating utility boilers; (2) industrial, commercial and institutional boilers; (3) combustion turbines, and (4) process heaters. Only existing or planned CAAA-related controls are considered in calculating budgets for other sectors (area and mobile sources) contributing to NOx emissions. States ultimately have discretion in deciding which sources to regulate to achieve the budget level.

The analyses of benefits in this RIA are based on a range of assumptions concerning the major stationary sources that will actually be targeted for additional controls by the States in implementing the NOx SIP call. The primary assumption in this analysis is that States will likely require NOx emissions reduction requirements from the largest electricity generating utility boilers, industrial, commercial and institutional boilers and combustion turbines.

Large electricity generating units are defined as those generating more than 25 megawatts (MW). Large industrial boilers, combustion turbines, reciprocating internal combustion engines, and other industrial NOx sources are those capable of firing greater than 250 mmBtu/hour.

2.1.4 Stringency of Control Level

In order to develop a cost-effective NOx reduction strategy as a basis for establishing State budgets, EPA considered various emission reduction levels by the affected sources for the summer ozone season defined as May 1 through September 30. For the electricity generating units (EGUs), EPA considered emissions budgets based on emission limits of 0.12 lb/mmBtu, 0.15 lb/mmBtu, 0.20 lb/mmBtu, and 0.25 lb/mmBtu.[1] For the large industrial boilers and combustion turbines, EPA considered a uniform percent emission reduction from uncontrolled projected 2007 emission levels ranging from 40 percent to 70 percent. For process heaters, EPA considered source category-specific control levels corresponding to cost-effectiveness cut-offs ranging from $1,500/ton to $5,000/ton.

It should be noted EPA decided not to impose controls on process heaters as part of this final rule based on the cost-effectiveness of controls for this source category. Process heaters is one of the source categories named in the petitions submitted by downwind States under the authority of Section 126 of the Clean Air Act (CAA). However, EPA's cost analysis for the final NOx SIP call showed that when emission reductions are considered at all large process heating sources in the final Section 126 region, the resulting average cost-effectiveness clearly exceeded the Agency's $2,000/ton (1990 dollars) framework. Since the costs of control per ton emission reduction for this source category exceeds EPA's limit for highly cost-effective emission reductions, it is not subject to control in the final Section 126 region. For more details, refer to Chapter 7.

Taking into consideration the emission reductions and associated costs projected under each of the above scenarios, EPA identified cost-effective NOx reduction strategies. Based on the reduced emissions achieved by these strategies applied to the source categories named in the eight Section 126 petitions, EPA then established State-specific budgets for ozone season NOx emissions. Alternative budgets are calculated for the different stringency levels considered for

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[1] Limits for each electricity generating unit are expressed as a specific NOx limit of lbs. of NOx per mmBtu of summer heat input projected for 2007, the year that was the focus of OTAG's analysis (the year for which air quality modeling was done).

EGUs. The details of NOx budget development can be found in the budget technical support document (EPA, 1999b).

2.1.5 Effective Dates

The affected sources in the States must implement NOx controls by May 1, 2003.

2.1.6 Emissions Budget Trading System Design

To allow for use of the most cost-effective emission reduction alternatives, an emissions budget trading program is an optional component of this final rule. Each of the States subject to the final Section 126 rule are encouraged to participate in this NOx Budget Trading Program and thereby provide a mechanism for sources to achieve cost-effective NOx reductions. The trading unit is a NOx Allowance, equal to one ton of emitted NOx. The Federal Register notice accompanying this final rule contains details of the trading program. Results of modeling the trading program are provided in Chapter 6 of this RIA, and in the notice accompanying the final rule.

Under the NOx Budget Trading Program, each of the participating States determines how its seasonal State trading program budget is allocated among its sources. Each source is given a certain quantity of NOx allowances. If a source's actual NOx emissions exceed its allocated NOx allowances, the source may purchase additional allowances. Conversely, if a source's actual NOx emissions are below its allocated NOx allowances, then it may sell the additional NOx allowances. Such a program creates a competitive market for NOx allowances that encourages use of the most efficient means for reducing NOx emissions.

For purposes of this analysis, trading may occur among any of the sources within the entire final Section 126 region or within each of the subregions. Where subregions are developed for the final Section 126 region, only intra-regional (within the region) trading is allowed.

Banking allows sources that do not use all of their NOx allowances for a given year to save them for later use. If banking is allowed, however, mechanisms such as flow controls can be put in place to limit the level of exceedance of the emissions cap. Flow controls limit the use of the banked NOx allowances by restricting their use at certain times or within certain areas. For example, a restriction may be placed on the banked allowances that allows only a set amount to be used during a defined time period.

For this RIA, EPA analyzed a variety of trading options. Trading with banking only is assumed for the 0.15 trading option, where banking begins after the start of the program in 2003. Banking of "early" reductions was not modeled for the 0.15 option because earlier IPM analysis suggested that owners of electricity generating units would want to use it to a very limited degree to lower the costs of future compliance (EPA, 1999). The following considerations were part of the 1999 analysis:

- Beginning in 2003 (and each year thereafter), the fossil fuel-fired electricity generating units over 25 MW in the SIP call region are assumed to hold NOx allowances during the summer ozone season equal to 489 thousand tons.

- Electricity generating units can trade allowances without restrictions, bank them for later use, or sell them to another electricity generation unit. Trading can occur within the entire SIP call region.

- Analysis is completed with and without flow controls.

EPA's analysis in 1999 was conducted using the 1998 version of the Integrated Planning Model (IPM) (EPA, 1998). EPA's analysis shows that on strict economic grounds, (i.e., under minimization of the total direct operating costs over the simulation period) limited banking was forecasted by the IPM based on the scenarios described above.   For more details concerning the IPM, please refer to Chapter 4.

2.2 References

OTAG, 1997a. *Draft of Costs of NOx Control Strategies on Electric Power Generation Using the Integrated Planning Model*. For incorporation into the OTAG Final Report, June 1997.

U.S. Environmental Protection Agency, 1997a. *Proposed Ozone Transport Rulemaking Regulatory Analysis*. Office of Air and Radiation, Washington, D.C., September 1997.

U.S. Environmental Protection Agency, 1998a. *Analyzing Electric Power Generation under the CAAA.* Office of Air and Radiation, Washington, D.C., March 1998.

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U.S. Environmental Protection Agency, 1999. *Modeling Electric Power in the Industrial Sector: An Integrated Approach*. Office of Atmospheric Programs, Acid Rain Division, Washington, D.C., April 1999.

Chapter 3.   Profile Of Regulated Entities

This chapter describes the sources potentially affected by the final Section 126 rule. Profiles of the sizes, types, locations, and NOx emissions characteristics of potentially affected electricity generating units, large industrial boilers, and combustion turbines are presented. The OTAG 1990 data base was the starting point for development of the inventory of sources considered in this report, and many updates to that database have been made by EPA (EPA, 1998).

Additionally, this chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The results presented in this chapter take into account changes that have been made to the NOx emissions inventory. These changes are the result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy resulting from EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS.

The universe of sources affected in this rulemaking is based on the source categories named in the petitions submitted to EPA under Section 126. The stationary source categories named in the petitions are large utilities, industrial boilers, combustion turbines, and process heaters. As mentioned in the final rule preamble, the definition of large source is 25 MW unit design capacity for utilities and greater than 250 mmBTU/hr for non-EGU sources. EPA is basing emissions control decisions on the average cost-effectiveness of achieving NOx reductions during the ozone season. Based on these decisions, process heaters are not affected by this rule. The methodology used to analyze the cost and average cost-effectiveness of alternative control levels is discussed in Chapters 4 and 5. The analysis and results supporting these decisions are found in Chapters 6 and 7. It should be noted that the total number of sources included in this analysis and other information provided in this chapter reflect complete coverage of all States affected by this rulemaking.

As noted in Chapter 2, EPA identified parts of 12 States plus the District of Columbia (i.e., 13 jurisdictions) as significantly contributing to nonattainment of, or interfering with maintenance of, the 1-hour ozone air quality standards in a downwind State. The final Section 126 region consists of whole or parts of Delaware, District of Columbia, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The petitions filed with EPA only name parts of Indiana, Michigan, Kentucky, and New York while naming the whole of the other jurisdictions.

3.1 Electricity Generating Units

In 1990, approximately 2.8 trillion kilowatt hours (kWh) of electricity were generated in the United States and were used in roughly equal proportions by industry, commercial establishments, and households. By 2005, EPA projects this total to increase to about 3.6 trillion kWh.[1] Most of this electricity, almost 70 percent, is generated at fossil fuel-fired power plants, with coal accounting for most of the fossil fuel used in these plants.

More than 95 percent of the nation's generating capacity is owned by the electric utilities. Although utilities are generally granted monopolies for their service territories, the rates utilities may charge are regulated by the authorities that grant the monopoly (known as a "franchise"). Rates for investor-owned utilities have theoretically been set high enough to cover all reasonably incurred costs, including capital investments, and to provide an allowance for a reasonable rate of return on invested capital. This arrangement has insulated, to a large extent, most large producers of electricity from some of the effects of the market as well as from regulatory costs. A changing regulatory and economic environment, however, is eroding this insulation. In the future, individual utilities are expected to be less able to pass on their emission control costs. Chapters 4 and 6 provide detailed analyses of the cost, emissions and economic impacts to the electric power industry.

A significant portion of the nation's electricity generating industry is in the region affected by the final Section 126 rule.[2] EPA estimates that 842 electrical generating units of less than 25 MW will be operating in this region in the year 2000. In addition to electric utility power units that produce only electricity, this number includes units owned by independent power producers (IPPs). This number also includes units that co-generate electricity and steam (co-generators), whether owned by utilities or IPPs. Table 3-1 presents the number of fossil-fueled units by capacity range and type (i.e., coal steam, combined cycle, combustion turbine, and oil/gas steam). Approximately 43 percent of the affected fossil-fueled electric utility units have capacities that are less than or equal to 100 megawatts (MW). About one percent are greater than 1,000 MW. Table 3-2 presents the distribution of these units as a percentage by type within each capacity range. About 59 percent of these units are coal powered, providing approximately 72 percent of fossil-fueled capacity. Approximately 21 percent of the units are combustion turbines, which provide about 7 percent of the capacity of all these units. The table indicates that coal powered units make up the majority of the capacity of all units.

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[1] EPA's generation requirement projections are based on an extension of the electric demand forecast of the North American Electric Reliability Council, adjusted for the impact of the Climate Change Action Plan.

[2] Analysis in this chapter assumes the entire States of MI, Indiana, KY, and NY are affected by this final Section 126 rule even though only parts of these States are covered in the final Section 126 rule. For further discussion see Chapter 6.1.5.

Table 3-1
Distribution of Capacities of Potentially Affected Electricity Generating Utility Units by Type in the Year 2000

Boiler Capacity	Coal Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total*	
	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)
0-25 MW[a]	3	36	0	0	0	0	0	0	3	36
>25-100 MW	147	9955	52	3,001	140	8,030	24	1,771	363	22,756
>100-200 MW	153	22,629	16	2,341	29	3,820	30	4,219	228	33,009
>200-400 MW	82	22,801	7	1,825	4	1,011	18	6,103	111	31,740
>400-600 MW	58	29,869	0	0	0	0	3	1,336	61	31,205
>600-800 MW	39	27,036	2	1,327	0	0	11	7,274	52	35,637
>800-1000 MW	6	5,182	0	0	0	0	7	5,994	13	11,176
>1000 MW	9	11,340	2	2,093	0	0	0	0	11	13,433
Total*	**497**	**128,848**	**79**	**10,586**	**173**	**12,861**	**93**	**26,696**	**842**	**178,991**

Source: IPM data, ICF Resources.
* Numbers may not sum due to rounding.
a Included are waste coal plants that are not affected but have been modeled as affected plants to avoid model complexity.

Table 3-2
Distribution of Capacities of Potentially Affected Electricity Generating Utility Units in the Year 2000

Boiler Capacity	Coal Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total*	
	% units in capacity range	% capacity in capacity range	% units in capacity range	% capacity in capacity range	% units in capacity range	% capacity in capacity range	% units in capacity range	% capacity in capacity range	% units in capacity range	% capacity in capacity range
0-25 MW[a]	100%	100%	0%	0%	0%	0%	0%	0%	100%	100%
>25-100 MW	40%	44%	14%	13%	39%	35%	7%	8%	100%	100%
>100-200 MW	67%	69%	7%	7%	13%	12%	13%	13%	100%	100%
>200-400 MW	74%	72%	6%	6%	4%	3%	16%	19%	100%	100%
>400-600 MW	95%	96%	0%	0%	0%	0%	5%	4%	100%	100%
>600-800 MW	75%	76%	4%	4%	0%	0%	21%	20%	100%	100%
>800-1000MW	46%	46%	0%	0%	0%	0%	54%	54%	100%	100%
>1000 MW	82%	84%	18%	16%	0%	0%	0%	0%	100%	100%
Total	59%	72%	9%	6%	21%	7%	11%	15%	100%	100%

Source: IPM data, ICF Resources.
* Numbers may not sum due to rounding.
a Included are waste coal plants that are not affected but have been modeled as affected plants to avoid model complexity.

Table 3-3 shows the geographic distribution and the total capacity of the affected electricity generating units by type (coal steam, combined cycle, combustion turbine, and oil/gas steam) among the States in the Section 126 region. Table 3-4 presents the same information in percentage terms. All States except the District of Columbia have coal-powered units and, for many States, coal-powered units make up the majority of the capacity of all units. The District of Columbia and West Virginia do not have any combustion turbine units. Further, several States do not have combined-cycle units.

Table 3-3
Distribution of Capacities of Affected Electricity Generating Utility Units (>25 MW) by State in the Year 2000

State	Coal Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total*	
	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)
Delaware	6	994	2	287	3	263	2	537	13	2,081
Dist. of Columbia	0	0	0	0	0	0	2	550	2	550
Indiana	63	18,815	0	0	14	835	0	0	77	19,650
Kentucky	52	13,910	0	0	13	1,385	1	115	66	15,410
Maryland	14	4,609	3	421	16	1,200	8	2,274	41	8,504
Michigan	57	11,422	1	1,055	4	143	7	2,620	69	15,241
New Jersey	8	2,032	18	2,633	33	3,134	16	2,275	75	10,073
New York	26	3,722	30	3,253	29	1,734	36	12,970	121	21,680
North Carolina	49	12,699	8	403	21	1,352	1	42	79	14,496
Ohio	80	22,019	3	196	14	920	1	100	98	23,235
Pennsylvania	74	18,380	6	430	14	761	14	3,389	108	22,961
Virginia	32	5,762	8	1,907	12	1,133	5	1,824	57	10,626
West Virginia	36	14,485	0	0	0	0	0	0	36	14,485
Total*	**497**	**128,848**	**79**	**10,586**	**173**	**12,861**	**93**	**26696**	**842**	**178,991**

Source: IPM data, ICF Resources.
* Numbers may not sum due to rounding.

Table 3-4
Distribution of Capacities of Affected Electricity Generating Utility Units by State and by Percentage in the Year 2000

State	Coal/Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total*	
	% of all Units in each State	% Capacity in each State (MW)	% of all Units in each State	% Capacity in each State (MW)	% of all Units in each State	% Capacity in each State (MW)	% of all Units in each State	% Capacity in each State (MW)	% of all Units	% of Capacity
Delaware	46%	48%	15%	14%	23%	13%	15%	26%	100%	100%
Dist. of Columbia	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%
Indiana	82%	96%	0%	0%	18%	4%	0%	0%	100%	100%
Kentucky	79%	90%	0%	0%	20%	9%	2%	1%	100%	100%
Maryland	34%	54%	7%	5%	39%	14%	20%	27%	100%	100%
Michigan	83%	75%	1%	7%	6%	1%	10%	17%	100%	100%
New Jersey	11%	20%	24%	26%	44%	31%	21%	23%	100%	100%
New York	21%	17%	25%	15%	24%	8%	30%	60%	100%	100%
North Carolina	62%	88%	10%	3%	27%	9%	1%	0%	100%	100%
Ohio	82%	95%	3%	1%	14%	4%	1%	0%	100%	100%
Pennsylvania	69%	80%	6%	2%	13%	3%	13%	15%	100%	100%
Virginia	56%	54%	14%	18%	21%	11%	9%	17%	100%	100%
West Virginia	100%	100%	0%	0%	0%	0%	0%	0%	100%	100%

Source: IPM data, ICF Resources.
* Numbers may not sum due to rounding.

Table 3-5 shows the distribution of electricity generating units by type and by NOx emission rate. The rates in this table are based upon Initial Base Case controls, which include existing Title IV controls, Reasonably Available Control Technology requirements, New Source Performance Standards (NSPS) for new and recently-built power plants, and implementation of Phase I of the Ozone Transport Commission Memorandum of Understanding (MOU). As shown in Table 3-5, about 40 percent of all units analyzed fall in the range of 0 to 0.2 lbs NOx/mmBtu. These units provide about one quarter of capacity in the Section 126 region. More than half of the capacity emits greater than 0.3 lbs of NOx/mmBtu. The table also shows that a significant majority of combined cycle, combustion turbine, and oil/gas steam units, in both number and capacity, fall in the lower ranges of NOx emission rates.

Table 3-5
Distribution of Fossil-Fueled Units Analyzed for Rulemaking by Initial Base Case NOx Emission Rate in the Year 2000

Initial Base Case Emission (lbs NOx/mmBtu)	Coal/Steam		Combined Cycle		Combustion Turbine		Oil/Gas Steam		Total*	
	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)	# of Units	Capacity (MW)
0.000-0.100	4	353	15	1,892	25	2,243	12	1,810	56	6,298
0.101-0.200	36	3,010	64	8,694	143	10,417	48	17,943	291	40,064
0.201-0.300	37	8,662	0	0	1	39	30	6,621	68	15,321
0.301-0.400	161	34,788	0	0	2	75	3	322	166	35,185
0.401-0.500	135	43,300	0	0	2	86	0	0	137	43,386
0.501-0.600	50	18,673	0	0	0	0	0	0	50	18,673
0.601-0.700	39	10,697	0	0	0	0	0	0	39	10,697
0.701-0.800	17	3,006	0	0	0	0	0	0	17	3,006
0.801-0.900	11	3,734	0	0	0	0	0	0	11	3,734
0.901-1.000	7	2,627	0	0	0	0	0	0	7	2,627
Total*	**497**	**128,848**	**79**	**10,586**	**173**	**12,861**	**93**	**26,696**	**842**	**178,991**

Source: IPM data, ICF Resources.
* Numbers may not sum due to rounding.

3.2 Industrial Boilers and Combustion Turbines

This section provides information on industrial boilers and combustion turbines, including the types of fuels they use and their emissions. Also included is a description of the industries that own them. Sources are classified by unit design capacity. Only large sources (as defined in Chapter 2) are assumed to be potentially affected by controls that a State may implement to meet its NOx budget level.

The following types of sources are described in this section:

- **Industrial, Commercial, and Institutional Boilers** - Industrial/commercial/institutional boilers (ICI boilers henceforth is referred to as industrial boilers) include steam and hot water generators with heat input capacities from 0.4 to 1,500 mmBtu/hr. These boilers are used in a range of applications, from commercial space heating to process steam generation, in all major industrial sectors. Although coal, oil, and natural gas are the primary fuels, many ICI boilers also burn a variety of industrial, municipal, and agricultural waste fuels (Pechan-Avanti Group, 1999).

- **Stationary Combustion Turbines** - Turbines are used in electric power generators, in gas pipeline pump and compressor drives, and in various process industries. This section includes turbines other than those used for electricity generation. The primary fuels used are natural gas and distillate oil, although residual fuel oil is used in a few applications (Pechan-Avanti Group, 1999).

Industrial boilers are owned and operated by a wide variety of industries, from traditional manufacturing to service industries like medical care and education. Thirty of the two-digit "major groups" in the Standard Industrial Classification (SIC) system include establishments with industrial boilers. The industries with the most industrial boilers are: chemicals, paper, petroleum, and primary metals. Table 3-6 shows the industry distribution of large industrial boilers and turbines in the 12 States plus the District of Columbia

Table 3-7 presents a breakdown of industrial boilers and combustion turbines by primary fuel type. Natural gas fired boilers account for the largest percentage of industrial boilers, with 36 percent of all boilers. Coal and oil industrial boilers make up the rest, with 30 percent and 12 percent of total boilers respectively. Other industrial boilers include wood and wood waste, pulping liquor, and waste gas. During the mid 1980s there was a trend towards use of dual-fuel boilers, where the preferred configuration was a natural gas system with a fuel oil back up.

Finally, Table 3-8 shows the distribution of large fossil-fuel fired industrial boilers and combustion turbines by state. For two industrial boilers, the data was not available to match a state with the source.

Table 3-6
Number of Industrial Boilers and Combustion Turbines by Industry[a]

SIC Code	Industry	Number of Industrial Boilers	Number of Combustion Turbines+
20	Food and kindred products mfgr.	7	0
22	Textile mill products	4	0
24	Wood kitchen cabinets	1	0
26	Pulp and paper mills, paperboard plants	51	2
28	Chemicals and allied products	56	1
29	Petrochemical products	38	1
30	Rubber and plastics products	4	0
32	Glass manufacturing	1	0
33	Primary metal industries	93	0
34	Fabricated metal products, excluding machinery and transportation equip.	2	0
37	Transportation equipment	8	1
38	Measuring instruments, photographic, medical and optical goods, clocks	4	0
39	Miscellaneous manufacturing industries	5	0
49	Electric, gas, and sanitary services	24	4
51	Wholesale trade - nondurable goods	1	0
79	Amusement and recreation services	3	0
80	Health services	2	0
82	Colleges and Universities	2	0
Federal Government		4	0
Other Government		2	0
TOTAL:		312	9

Source: Abt Associates, 1999. Based on 1995 year data.

Table 3-7
Number of Large Industrial Boilers and Combustion Turbines by Fuel*

Source Type - Fuel Type	Number of Sources
Industrial Boilers - Coal/Wall	63
Industrial Boilers - Coal/FBC	1
Industrial Boilers - Coal/Stoker	17
Industrial Boilers - Coal/Cyclone	3
Industrial Boilers -Residual Oil	40
Industrial Boilers -Distillate Oil	8
Industrial Boilers - Natural Gas	119
Industrial Boilers -Process Gas	59
Industrial Boilers - Coke	1
Industrial Boilers - Coal/LPG	1
Total Industrial Boilers	**312**
Combustion Turbines - Natural Gas	8
Combustion Turbines - Oil	1
Total Combustion Turbines	**9**
Total Industrial Boilers and Combustion Turbines	**321**

Source: Pechan-Avanti Group, 1999.
Note: Based on 1995 base year data.

Table 3-8
Number of Large Fossil-Fuel Fired Industrial Boilers and Combustion Turbines by State*

State	Number of Industrial Boilers	Number of Combustion Turbines
Delaware	4	0
District of Columbia	3	0
Indiana	52	1
Kentucky	12	1
Maryland	6	0
Michigan	33	2
New Jersey	54	2
New York	17	0
North Carolina	13	0
Ohio	45	0
Pennsylvania	39	3
Virginia	17	0
West Virginia	17	0
TOTAL:	**312**	**9**

Source: Pechan-Avanti Group, 1999.
Note: Based on 1995 base year data.

3.3 Overview of Baseline Emissions from Large Sources

Table 3-9 provides an overview of the contribution of various NOx sources to total baseline NOx emissions in the 12 States and the District of Columbia This table shows that large sources subject to new requirements under the Section 126 rule (including electricity generating units, industrial boilers, and combustion turbines) account for approximately 45 percent of the total projected baseline emissions in these States.

Table 3-9
Overview of 2007 Baseline Ozone Season NOx Emissions from Large Sources in the Final Section 126 Region

Source Category	Baseline 2007 Ozone Season Emissions	Percentage of Total 2007 Ozone Season Baseline Emissions
Electricity Generating Units	951,000	41%
Industrial Boilers	90,000	4
Combustion Turbines	1,000	0.04
Area/Mobile/Nonroad Sources	1,275,000	55
TOTAL:	2,317,000	100

Source: ICF, 1999, Pechan-Avanti Group, 1999.
na = not estimated or not applicable
[a] Due to rounding, percentages do not add to exactly 100%.
[b] Non-EGU units for which EPA was not able to identify control measures.

3.4 References

Abt Associates, Inc., 1999. *Non-Electricity Generating Unit Economic Impact Analysis for the Final Section 126 Petition Rulemaking*. Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, October 1999.

Pechan-Avanti Group, 1999. *Final Section 126 Petition Rulemaking Non-Electricity Generating Unit Cost Analysis.* Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1999.

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U.S. Environmental Protection Agency, 1997a. *Proposed Ozone Transport Rulemaking Regulatory Analysis*. Office of Air and Radiation, Washington, D.C., September 1997.

U.S. Environmental Protection Agency, 1996. *Regulatory Impact Analysis of NOx Regulations*. Office of Atmospheric Programs, Acid Rain Division, Washington, D.C., October 1996.

Chapter 4. Methodology For Estimating Emissions, Costs, And Economic Impacts For The Electric Power Industry

This chapter presents the methodology for estimating the costs, emission reductions, and impacts of the final section 126 rule for the electric power industry. The chapter is divided into nine sections, beginning with an analytical overview in Section 4.1. Section 4.2 discusses the use of the Integrated Planning Model (IPM) for the analysis, including assumptions about the baseline and about technologies for power generation and emission control. Allowance allocation and trading issues are presented in Section 4.3, and the estimation of administrative costs is discussed in Section 4.4. These discussions are followed by Sections 4.5 and 4.6, which outline the analysis of potential direct and indirect economic impacts. Limitations of the analysis are presented in Section 4.7. References are presented in Section 4.8 of the chapter.

This chapter provides methodology associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The methodology presented in this chapter takes into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999. In addition, the methodology takes into account the narrowed geographic scope and sources affected by the section 126 remedy as a result of EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS. It should be noted that the methodology primarily reflect application of the final section 126 remedy to all sources in a named source category in each State in the final section 126 region.

4.1 Analytical Overview

The basic approach to estimating the potential effects of the final section 126 rule on electricity producers is to project their actions in the absence of the rule; project their actions if they were subject to the rule; and then compare the two sets of actions. Subtracting the total costs of generating electricity in the absence of the rule from the total costs under the rule, for example, yields the total costs of the rule itself if sources respond to the rule as modeled in this report. Similarly, subtracting estimated emissions, generation, and capacity yield the effects of the rule in these three areas.

The scope of these analyses is wide both geographically and in terms of time. While the focus of the rule is on the 13 jurisdictions affected by the final section 126 rule, the analysis projects the actions of utilities (and non-utility generators) in all 48 contiguous States in order to capture effects that can spill out of one region into neighboring areas. Rather than examining only a snapshot in time, the analysis covers a period starting in 2001 and running out to 2025.[1] For most of the comparisons (in Chapter 6), results are presented only for the year 2007. Examining the industry over many years makes it possible to take many important dynamic effects into account. For example, the effects of efficiency gains over time and the choice between capital-intensive control measures and measures that increase operating costs can be investigated by projecting utility response over a long analytical period. In addition, the effects of allowing the banking of emission reductions can be analyzed only in a dynamic framework.

The actions of electricity generators over time are projected using IPM, which is a detailed computer model of the electric power industry. IPM is designed to find the most efficient (that is, the least-cost) way to satisfy the demand for electricity under a series of limitations or constraints. The constraints under which IPM "produces" electricity can include a limit on tons of NOx emissions during the summer ozone season, and it is by setting this constraint that the effects of the final section 126 rule can be modeled. Running IPM without a section 126 limit on tons of NOx emissions produces a picture of the baseline situation in which the final section 126 rule is not in effect. Rerunning IPM after adding a constraint that limits emissions in the section 126 region to a specified number of summer tons (e.g., 340,000, under the 0.15 alternative) shows what the industry would do to comply with the rule while keeping its costs as low as possible. Additional runs with different sets of constraints are conducted to assess other options, while additional runs with different assumptions make it possible to test the sensitivity of the results. More detail on how IPM operates is provided in Section 4.2 below and in *Analyzing Electric Power Generation Under the CAAA,* Office of Air and Radiation, U.S. Environmental Protection Agency, March 1998. This information and the model runs conducted for the analysis can also be found at an EPA website with the address: http://www.epa.gov/capi.

The IPM runs for the baseline and the various options constitute the heart of the analysis. Before the results can be presented, however, additional analyses must be conducted to interpret these runs. For example, in some cases it is necessary to aggregate the detailed results into totals by State and region, or to divide the cost changes by emission changes to estimate cost effectiveness. In addition, tracing the potential economic impacts of changes in costs and electricity prices beyond the electricity generating industry is outside of the scope of IPM, and must be done using standard techniques of economic impact assessment (discussed in Sections 4.5 and 4.6).

4.2 IPM Assumptions and Use

EPA uses IPM to evaluate the emissions and potential cost impacts expected to result from the requirements of the final section 126 rule on the electric power industry. IPM has been used for over ten years by electric utilities, trade associations, and government agencies both in

[1] For this analysis, IPM does not run all calendar years, only 2001, 2003, 2005, 2007, and 2010. All calendar years are mapped on to model years as follows: 2000-2002, 2003-2004, 2005-2006, 2007, 2008-2015.

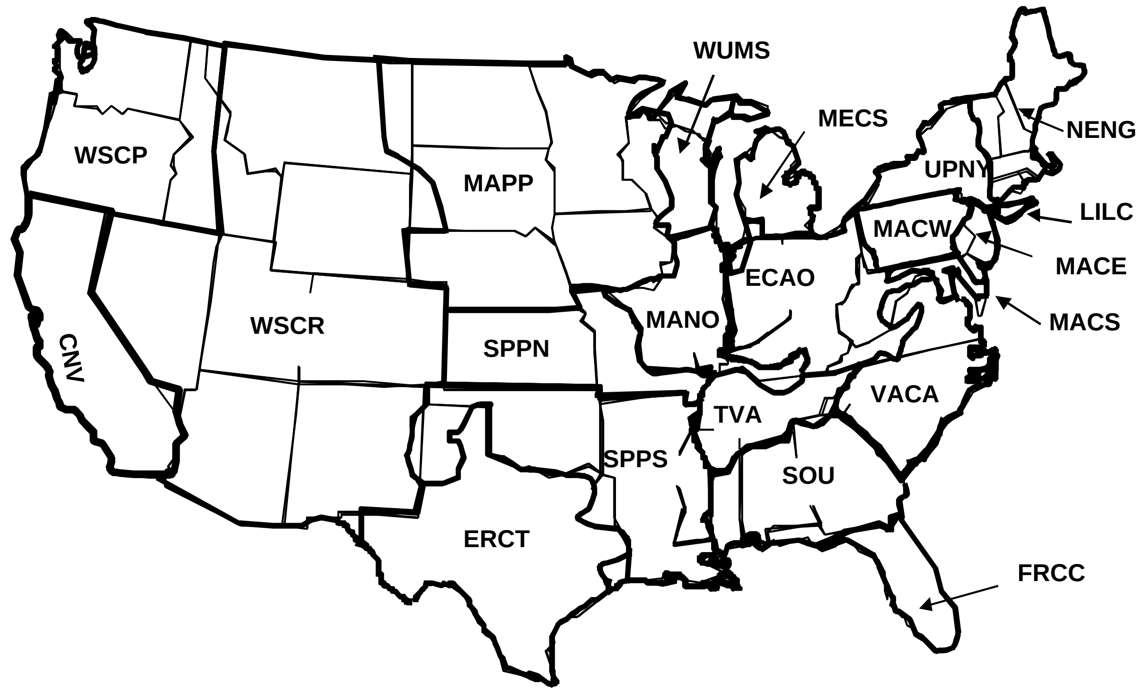
the U.S. and abroad to address a wide range of electric power market issues. The applications have included capacity planning, environmental policy and compliance planning, wholesale price forecasting, and asset valuation. EPA has used IPM extensively for environmental policy and regulatory analysis. In particular, EPA has used IPM to analyze NOx emission policy and regulations as part of the Clean Air Power Initiative (CAPI) in 1996, as an analytical tool for the Regulatory Impact Analysis of the National Ambient Air Quality Standards (NAAQS) for ozone and particulates in 1997, as a tool to analyze alternative trading and banking programs during the OTAG process in 1996 and 1997, and to support the Regulatory Impact Analysis for the NOx SIP call. IPM was also used for the regulatory analysis of the section 126 notice of proposed rulemaking.

IPM has undergone extensive review and validation over this ten-year period. In April 1996, EPA requested participants in the CAPI process to comment on the Agency's new approach to forecasting electric power generation and selected air emissions. EPA received many helpful comments and made a series of changes in its methodology and assumptions based on commenters' recommendations. Most recently, IPM and EPA's modeling assumptions were reviewed as part of the OTAG process. Again, changes were made to the methodology and assumptions based on commenters' recommendations.

The version of IPM used by EPA (IPM98) represents the U.S. electric power market in 21 regions, as depicted in Figure 4-1. These regions correspond in most cases to the regions and sub-regions used by the North American Electric Reliability Council (NERC). IPM models the electricity demand, generation, transmission, and distribution within each region as well as the transmission grid that connects the regions.

The model includes existing utility power plants as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market. Data on the existing boiler and generator population, which consists of close to 8,000 records, are maintained in EPA's National Electric Energy Data System (NEEDS). In order to make the modeling more time and cost efficient, the individual boiler and generator data are aggregated into "model" plants. EPA's application of the model has focused heavily on understanding the future operations of coal-fired units, which will have the greatest air emissions among the fossil-fired units. The operation of other types of non-fossil fuel-fired generation capacity, including nuclear and renewables, are also simulated but at a higher degree of aggregation.

Figure 4-1
Integrated Planning Model Regions in the Configuration Used by EPA



Working with these existing model plants and representations of alternative new power plant options, IPM determines the least-cost means for supplying electricity demand while limiting air emissions to remain below specified policy limits. Multiple air emissions policies can be modeled simultaneously. For example, IPM is used in this study to simulate compliance with existing CAAA Title IV SO_2 emission requirements as well as actions that EPA has considered for controlling the ozone season NOx emissions in the States covered by the final section 126 rule. While determining the least-cost solution, IPM also determines the optimal compliance strategy for each model plant. A wide range of compliance options are evaluated, including the following:

- Fuel Switching – For example, switching from high sulfur coal to low sulfur coal.
- Repowering – For example, repowering an existing coal plant to a gas combined-cycle plant.

- Pollution Control Retrofit – For example, installing selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or gas reburn (to reduce NOx emissions), or flue gas desulfurization (to control SO_2 emissions).

- Economic Retirement – For example, retiring an oil or gas steam plant.

- Dispatch Adjustments – For example, running high-NOx cyclone units less often, and low NOx combined-cycle plants more often.

- Trading – For example, buying allowances instead installing controls.

IPM provides estimates of air emission changes, incremental electric power generation costs, changes in fuel use, and other potential impacts for each air pollution policy analyzed.

The model is not limited in scope to facilities owned by electric utilities, but also includes independent power producers (IPP) that provide electricity to the power grid on a firm-contract basis, as well as IPP facilities larger than 25 megawatts that provide power on a non-firm basis.

IPM simultaneously models over an extended time period, and reports results for selected years. In addition to reporting for 2003, which is the year that the regulatory approach would begin, these analyses also provide results for 2001, 2005, 2007, and 2010.

In using IPM to analyze NOx emission policy over the past two years, EPA has developed a set of data and assumptions that reflect the best available information on the electricity market and operating factors. These data and assumptions can be grouped into the following four categories:

- **Macro Energy and Economic Assumptions** – These assumptions are related primarily to electricity demand projections, fuel prices, power plant availability, heat rates, lifetimes, and capacity factors. Also included in this category are discount rate and year dollar assumptions.

- **Electric Technology Cost and Performance** – These assumptions are related to electric technology cost and performance for existing and new plants, as well as for existing plant refurbishment and repowering.

- **Pollution Control Performance and Costs** – These assumptions primarily cover the performance and unit costs of pollution control technologies for NOx and SO_2.

- **Air Emissions Rates under the Base Case** – These assumptions cover current EPA and State requirements that will affect emission levels from various facilities. The focus has been on SO_2 and NOx controls.

Each of these sets of data and assumptions are briefly discussed below. More detail can be found in EPA's March 1998 report entitled *Analyzing Electric Power Generation under the CAAA*.

4.2.1 Macro Energy and Economic Assumptions

In developing the analysis for the final section 126 rule, EPA makes assumptions about major macro energy and economic factors, as shown in Table 4-1. See Appendix No. 2 of EPA's March 1998 report *Analyzing Electric Power Generation under the CAAA* for details on most of the macro energy and economic factors.

In this study, IPM's cost outputs are converted from real 1997 dollars to real 1990 dollars to be consistent with the cost analyses prepared for the final NOx SIP call and the Agency's recently published Regulatory Impact Analysis of the National Ambient Air Quality Standards for ozone and particulates. The factor used for this purpose is 0.8327, which corresponds to the gross domestic product implicit price deflator index published by the Bureau of Economic Analysis.

Table 4-1
Key Baseline Assumptions for Electricity Generation

Factor	Assumption
Discount Rate (percent per year)	6
Conversion Factor from 1997 to 1990 Dollars	0.8327
Electricity Demand Growth Rate (percent per year)[a]	1997-2000 = 1.6 2001-2010 = 1.8 > 2010 = 1.3
Reductions in electricity demand due to Climate Change Action Plan (Billion kwh) for sensitivity analysis in section 6.3.4	2001 = 100 2003 = 164 2005 = 228 2007 = 293 2010 = 389 >2019 = 608
Power Plant Lifetimes	Fossil Steam = 65 years if ≥ 50 MW = 45 years if < 50 MW Nuclear = 40 year license length Turbines = 30 years
U.S. Nuclear Capacity (gigawatts)	2001 = 93 2003 = 90 2005 = 87 2007 = 86 2010 = 81 2020 = 50

Nuclear Capacity Factors (percent)	2001 = 80 2003 = 80 2005 = 80 2007 = 82 2010 = 81 2020 = 83
World Oil Prices (1997$ per BBL)	2001 = 19.20 2003 = 19.90 2005 = 20.50 2007 = 20.80 2010 = 21.20 2020 = 22.40
Wellhead Natural Gas Price (1997$ per mmBtu)[b]	2001 = 1.90 2003 = 1.95 2005 = 2.00 2007 = 2.00 2010 = 2.00
Coal Steam Power Plant Availability (percent)	1995 = 82 2000 = 83.5 2005/10/20 = 85
Existing Power Plant Heat Rates	No change over time
Coal Mining Productivity Increases (percent change per year)	1995-1999 = 3.1 2000-2004 = 2.8 2005-2009 = 2.4 2010-2014 = 2.1 2015-2025 = 2.1
Average Delivered Coal Prices[b] (percent change per year 2001-2010)	-2.0

[a] Does not include any adjustment for potential improvements related to the Climate Change Action Plan.
[b] Based on recent ICF analyses using updated coal mining productivity and supply for coal, and technology and supply assumptions for gas. Note that the natural gas prices are not an assumption in the model, but are a forecast of the model.

4.2.2 Electric Energy Cost and Performance Assumptions

In order to simulate the electric power market under baseline conditions and for each of the regulatory options, assumptions are made on the cost and performance of new power plants as well as for repowering existing power plants. These characterizations of new power plant cost and performance are used in IPM to determine the least cost means for meeting projected future electricity requirements subject to the baseline emission restrictions and the NOx emission limits specified for each regulatory option.

Power plant cost and performance assumptions are developed for the following new conventional and unconventional power plant types:

- New Conventional Power Plants

    - Conventional Pulverized Coal;
    - Advanced Coal (Integrated Gasification Combined Cycle - IGCC);
    - Combined Cycle;
    - Combustion Turbine; and
    - Nuclear

- New Renewable/Nontraditional Options

    - Biomass IGCC;
    - Solar Photovoltaics;
    - Solar Thermal;
    - Geothermal; and
    - Wind

Cost and performance projections are developed for 2001, 2003, 2005, 2007, and 2010 in order to capture changes in technology over time. In general, the year 2001 estimates reflect generation technology that is close to or identical to existing technology, and the later year estimates reflect advancements in costs and performance. The Agency relies heavily on work that the Energy Information Administration did in support of the most recent *Annual Energy Outlooks* (AEO97 and AEO98). EIA had its approach peer-reviewed during its development.

In addition to the AEO, key data sources used to develop these assumptions are as follows:

EPRI, *TAG Technical Assessment Guide, Electricity Supply - 1993*, EPRI TR-102276-V1R7, June 1993;

SERI, *The Potential of Renewable Energy: An Interlaboratory White Paper*, SERI/TP-260-3674, March 1990; and

TVA, *Integrated Resource Plan Environmental Impact Statement*, Volume Two, Technical Documents, July 1995.

In addition to these assumptions on new power plants, EPA also develops assumptions on the cost and performance of repowering existing power plants. The following three types of repowering options are considered:

- Repowering Coal Steam to Integrated Gasification Combined-Cycle;

- Repowering Coal Steam to Gas Combined-Cycle; and

- Repowering Oil/Gas Steam to Gas Combined-Cycle.

The key sources of data for this section are the repowering studies conducted by Bechtel Corporation, the TVA Integrated Resource Plan EIS, and the EIA life extension report.

For more details on the assumptions made about the cost and performance of new power plants and repowering of existing power plants, see Appendix No. 3 of EPA's March 1998 report *Analyzing Electric Power Generation under the CAAA*.

4.2.3 Pollution Control Performance and Cost Assumptions

EPA develops pollution control cost and performance estimates for the following options:

- Coal-Fired Steam Electric Generating Units

  - Combustion Controls;
  - Selective Catalytic Reduction;
  - Selective Non-Catalytic Reduction; and
  - Natural Gas Reburn.

- Oil and Gas-Fired Steam Generating Units

  - Selective Catalytic Reduction; and
  - Selective Non-Catalytic Reduction.

EPA also develops cost and performance estimates for combining SCR or SNCR with coal plant scrubbers. With these options, the IPM can determine if, in some instances, it is optimal to place a scrubber <u>and</u> SCR or SNCR to reduce SO_2 emissions and NOx emissions from a given plant simultaneously. In determining the least-cost means for complying with a NOx regulatory policy, the model can choose from among these pollution control options and change the dispatch of model plants. For example, the model in some cases can reduce the utilization of high NOx emitting units and increase the utilization of low NOx emitting units.

In addition to including the pollution control cost and performance estimates described above, IPM also takes into account the cost and performance of combustion controls installed beyond those resulting from implementation of Title IV and Title I (Reasonable Available Control Technologies - RACT) requirements. Note that the Title IV NOx program permits an owner/operator to comply with the requirements by averaging the NOx emissions from some units within the owner/operator system with emissions from other units also within the same system. This emissions averaging allows an owner/operator to install controls on units that are cost-effective to control and average emissions from these units with emissions from units that are less cost-effective to control. EPA accounts for the cost of combustion controls beyond those needed for Title IV compliance in the following manner: (1) EPA identifies the units that either are (Phase I units) or are likely to (Phase II units) average their emissions with other controlled units, and (2) EPA reasons that these uncontrolled units, for the purposes of this rulemaking, will install the least expensive controls, that is, combustion controls, where requirements beyond Title IV are imposed on them. These units can further reduce their emissions by installing SCR, SNCR, or gas reburn, as described above. Additionally, using continuous emissions monitoring (CEM) data, EPA found that some sources with a common owner or operator, that could average their emissions under Title IV, consistently emitted well below (20 percent or more) their Title IV mandated levels. For the purposes of analyses in this report, such sources are assumed to emit at their actual CEM-measured levels, not their applicable Title IV standard.

These performance and pollution control cost assumptions for NOx are based on the following sources:

U.S. Environmental Protection Agency, *Regulatory Impact Analysis of NOx Regulations*, October 1996;

Bechtel Power Corporation, *Cost Estimates for NOx Control Technologies Final Report*, February 1996;

Bechtel Power Corporation, *Draft Technical Study on the Use of Gas Reburn to Control NOx at Coal-fired Electric Generating Units*, June 1996; and

Acurex Environmental Corporation, *Phase II NOx Controls for NESCAUM and MARAMA Region*, 1995.

For more details on the assumptions made about pollution control cost and performance see Appendix No. 5 of EPA's March 1998 report, *Analyzing Electric Power Generation under the CAAA*.

4.2.4 Air Emissions Rates under the Base Case

Assumptions about the other environmental rules that will be in effect with or without the final section 126 rule constitute a vital aspect of the baseline because even existing environmental initiatives will lead to NOx reductions in the future. If the reductions that are projected to take place under these initiatives are not accounted for, the effects of the rule in capping NOx emissions will be overestimated.

Three sets of regulations affecting NOx emissions in the baseline are taken into account in this analysis. First, EPA factors in regulations under Title I of the Clean Air Act, including RACT requirements for existing sources, EPA's New Source Performance Standards, and controls based on Best Available Control Technology (BACT) and Lowest Achievable Emissions Rates (LAER) that would be in effect for new sources. The analysis also accounts for the NOx reductions from utility units under Phases I and II of Title IV's Acid Rain Program, which set rate limitations for most coal-fired generators greater than 25 MW of capacity. Note that the SIP call is not assumed to be in effect for the purposes of this analysis.

Finally, the control program agreed upon by the Ozone Transport Commission for the Ozone Transport Region is assumed to go forward in the baseline. The OTC's Memorandum of Understanding envisions three progressively more stringent control requirements for sources in the OTR: Phase I, Phase II, and Phase III. Though EPA anticipates that all three of these phases will eventually be implemented in the baseline, cases including Phase I alone (i.e., RACT controls in place in the OTR) are examined in some of the baseline analyses. This baseline, which is referred to as the *Initial Base Case*, is the primary basis for comparison in this RIA. Comparisons of the options to a *Final Base Case*, which assumes that Phase II and Phase III of the OTC's MOU will also go into effect, are also made in the RIA. Because Phases II and III are estimated to cut NOx from electric generators, any comparison of an option to the Initial Base Case will appear to be more effective (and more costly) than a comparison of that option to the Final Base Case. In considering the effects of the OTC's MOU, this analysis covers only the NOx controls in the section 126 region. Thus NOx controls resulting from the OTC MOU in Maine, Vermont, and New Hampshire are not included.

4.3 Allowance Allocations and Trading

For the purposes of this analysis, the final section 126 rule is assumed to be implemented through an emissions trading program. The trading program works by allocating the limited rights to emit NOx in limited quantities during the summer, and allowing sources to choose the extent to which they will reduce emissions or purchase these limited rights or "allowances." For many aspects of the analysis, the initial distribution of the allowances is not important; the only relevant fact regarding the allowances is their total volume, which determines the number of tons of NOx reductions required. The reasons for this separation of the allowance allocations from the rest of the analysis, and the circumstances under which the allocation does become important, are described in Section 4.4.1. Assumptions about the trading of allowances are presented in Section 4.4.2.

4.3.1 Purpose of Allowances and Assumptions about Allocations

IPM works by finding the least-cost method for producing electric power for the industry as a whole, assuming the entire industry in the area of the final section 126 rule is subject to an overall cap on ozone season NOx emissions. The model places pollution controls or makes dispatch changes to electricity generating units that lead to the achievement of emission reductions at the lowest cost. As a result, some firms' power plants are projected to be tightly controlled, at significant cost, while other firms' plants have no controls beyond those assumed in the baseline.

Realistically, this pattern would not be seen unless some system existed to give incentives to the firms with the most cost-effective control possibilities to bear the greatest part of the control burden. The final section 126 rule envisions that these incentives will take the form of compensation for allowances, which must be purchased by the firms that elect to under-control their plants' emissions. Firms are assumed to either buy or sell allowances depending on their own costs of control in comparison to the market price of allowances. As the price reacts to changes in demands and supplies of allowances, the market will help ensure that the costs of incremental reductions of NOx are the same for all participants.

Projecting how the NOx emissions cap will be divided initially among firms through awards of allowances is not important for estimating the total costs of the final section 126 rule or the control methods that will be used if it can be assumed that the allowance market will be efficient and that the allocation is made "once and for all." If the market is efficient, the only effect of allocating more allowances to a given firm will be that a firm will be able to sell more allowances after controlling emissions to an efficient degree. Experience with the SO_2 allowance market under Title IV demonstrated that these markets can function efficiently, with significant trading volumes and minimal costs (U.S. EPA, Draft Fall 1998).

The initial distribution of the allowances is, however, very important in assessing potential impacts and trading patterns. If, for example, allowances are distributed in proportion to baseline NOx emissions, owners of coal plants would be able to sell many more allowances than if allowances are distributed in proportion to baseline generation.

For the modeling of compliance costs, it is assumed that allowances will be divided only among existing affected sources, in proportion to their 1995 or 1996 fuel input, allowing for growth in electricity output to 2007[2]. The assumptions do not provide for shifts in allowance distributions over time in response to changing capacity use, unit closures, and new builds. These simplifications should have little effect on the analysis. If, however, EPA decides to allocate on an updating output basis, the outcome could be much different.

4.4 Administrative Costs

Electric utilities and EPA will incur administrative costs in addition to the costs of complying with the final section 126 rule. The primary basis for determining the amount of these administrative costs is supporting data from EPA's Information Collection Request (ICR) (EPA,1998e) for the proposed rule. All of the administrative costs are annualized and presented in 1990 dollars for the year 2007.

[2] For the purpose of assessing the pattern and volume of allowance transactions, new units are assumed to be granted enough allowances to emit at their permitted rates.

4.4.1 Administrative Costs to Affected Electric Generating Units

The owners or operators of affected electricity generating units will incur administrative costs associated with the following activities:

- Monitoring emissions;
- Certifying compliance;
- Modifying permits; and
- Trading allowances.

Electricity generating units will be required to have in place monitoring equipment to measure their NOx emissions. This requirement is already in force under CAA Title IV for units covered by the SO_2 allowance program. In addition, electricity generating units will be required to submit a monitoring plan to EPA for review and approval. On a regular basis, they must also submit a report certifying compliance. The sources will also be required to obtain air permits and, before beginning construction of the control technologies, the facilities may need a construction permit. The operating permit will also need revision to incorporate the revised emission limitations. Estimates of these administrative costs are based on supporting data from EPA's ICR (EPA,1998e). In general, the administrative costs are equal to the unit costs multiplied by the number of affected electricity generating units.

Utilities will also incur transaction costs in trading allowances between companies. The methodology for estimating transaction costs is discussed next.

4.4.2 Transaction Costs of Trading Allowances

IPM calculates costs and emission reduction choices as though there are no constraints on the transfer of allowances from source to source. Implicitly, then, the analysis assumes a completely efficient, frictionless market for allowances. More realistically, there will be some transaction costs incurred when allowances are transferred. The transaction costs include the costs to gather information on the market, search for allowances, make bids and offers, negotiate terms and conditions of allowance transfer agreements, and ensure that the allowances transfer. Many companies will hire an emissions trading broker to perform these services, but the individual companies affected will also incur other costs related to the decision-making process as well as costs of legal counsel.

For this analysis of the NOx market, EPA assumes that total transaction costs are approximately 1.5 percent of the value of the allowances traded. In reality, the percentage may vary depending upon the quantity of allowances traded, the familiarity of the traders with the market, and the overall maturity of the market. While total SO_2 transaction costs have declined over time, recent evidence suggests total SO_2 transaction costs range from one to two percent (U.S. EPA, Forthcoming-Fall 1999).[3] These total transaction cost estimates are for both buyer and seller combined and include brokerage fees and internal decision-making costs. The decline in total transaction costs is believed to be attributable to improved market maturity and trading familiarity. This analysis assumes an average total transaction cost of 1.5 percent for the NOx market, thus accounting for market variation over time. Here we are only counting inter-utility trading costs. There will also be intra-utility trading, but no costs are assigned to these trades.

The total value of allowances traded between companies under each option is equal to the product of the number of allowances and the price of an allowance estimated for each option. For this analysis, EPA projects the value of each allowance and the volume of allowances traded between units and between utilities. EPA estimates the total volume of allowance transactions for the 0.15 trading option by comparing IPM projections for emissions for each unit to an estimate of the allowances that the unit would receive under the final section 126 rule. Allowance allocations are assumed to be made based on the baseline fuel inputs of the units (IPM projections for the year 2007 in the baseline are used as a proxy for these baseline fuel units. New units, for simplicity, are assumed to be allocated allowances equal to their permitted emissions). The difference between each unit's emissions and the allocated allowances is assumed to be equal to the amount of each allowance transaction, either the quantity acquired or transferred to another. Then, the total quantity is found by summing all allowances acquired across all units. To determine the number of transactions occurring between companies, the emissions for each unit are summed on a utility-by-utility basis and compared to the sum of the allowances allocated to each unit on utility-by-utility basis. The difference of the two is equal to the total inter-utility transactions. Due to the difficulty of identifying the ultimate owner of each non-utility unit, each non-utility power plant is treated as a separate company for the purposes of estimating inter-company transactions.

The number of transactions will be greater or fewer for each regulatory option based on the differences between the marginal cost functions at the various control levels as well as the shapes of these cost functions. Transaction volumes are calculated for the 0.15 option only; volumes for the other options are estimated based on the relative transaction volumes found in the analysis of the NOx SIP call. The price of allowances is assumed to be approximately equal to the marginal cost of NOx reductions, as estimated by IPM.

Transaction costs were derived based on trading between firms operating electric power plants only. Transaction costs for firms operating non-EGU sources were not estimated. Since the transaction costs are only a very small component of total annual compliance costs of the final section 126 rule for affected utilities and will likely be a very small component of total annual compliance costs for affected non-EGU sources, the inclusion of non-EGU transaction costs should not significantly change the compliance costs estimate of the rule.

[3] These numbers are based on preliminary estimates and may change in the final report.

4.4.3 Administrative Costs to EPA

The administrative costs to EPA include the following:

- Certifying monitoring plans;
- Monitoring compliance by conducting audits;
- Reviewing and approving permit modification applications;
- Upgrading the allowance tracking system;
- Administering the allowance tracking system; and
- Collecting the NOx emissions monitoring data.

EPA will need to certify monitoring plans prepared by affected sources. EPA will also monitor the compliance of electric generating units by reviewing the emissions data and conducting occasional audits. It is assumed that EPA will audit 10 percent of the EGUs. The Agency will also be responsible for reviewing and approving permit applications for both construction and operating permits.

In addition, EPA will incur administrative costs associated with upgrading the allowance tracking system, administering the allowance tracking system, and collecting the NOx emissions monitoring data. This effort is incremental to current EPA collection of NOx emissions data from acid rain units and certain OTC units that already provide emissions data. EPA recently modified the allowance and emissions tracking systems for the Ozone Transport Commission's NOx Budget Program; therefore, these systems will require minimal upgrades to expand to the section 126 region. The administrative costs to EPA are calculated by multiplying the unit costs and the number of affected units based on supporting data from EPA's ICR (EPA, 1998e).

4.5 Direct Economic Impacts

The Agency analyzed the potential direct impacts of the rule on the electric power producers.

4.5.1 Potential Costs to Electric Power Producers Relative to Revenues

Costs of the final section 126 rule for this illustrative implementation approach are compared to the revenues of electric power producers at two levels: industry-wide and to small entities. Industry-wide comparisons are made by expressing the potential costs of the rule on a per-kilowatt hour basis, using IPM outputs on the generation of electricity from fossil fuel, and then comparing this increase in unit costs to average rates per kilowatt hour. Data are obtained from EIA Form 861 to find revenues per kilowatt hour for utilities in the SIP call region, which are assumed to be almost identical to revenues in the section 126 region.

Potential costs to small entities are estimated in more detail. Specific data on small utility revenues is collected from EIA Form 861, and total revenues for small non-utility owners is obtained from Dun & Bradstreet. These revenue estimates are compared to cost estimates for individual units owned by each small entity. The cost estimates take into account the least-cost means of compliance, including the option of allowance purchases, as discussed below.

The IPM analysis focuses on estimating industry-wide costs and emission reductions. Where it is necessary to derive rough estimates of potential costs for particular firms, the first step is to find the projected emission control choices made for each of the firm's units in the cost-minimizing solution. The cost functions built into IPM can then be used to calculate the fixed and variable control costs for each unit, and these costs are summed across all of the units owned by the firm to yield total control costs.

The next step in estimating potential costs to a given firm is to incorporate purchases or sales of allowances. Estimates of the total summer NOx emissions from the firm's plants are compared to the firm's allocation of allowances (based on an allocation of the section-126-region-wide cap in proportion to baseline fuel use). This comparison gives the net purchases or sales of allowances, which must then be multiplied by an estimated allowance price. Allowance price estimates are based on EPA estimates of the incremental costs per ton of reducing NOx. It should be noted that these potential firm-by-firm impacts do not take account of changes in dispatching, and can therefore overstate net economic impacts on the potentially affected entities. Allowance transaction costs are considered too small to be considered in this analysis, but are included in the analysis of administrative burden.

4.5.2 Assessment of Potential for Passing on Cost Increases

An assessment of the potential effects of the final section 126 rule on electricity prices is conducted using estimates of changes in marginal cost combined with judgment on the effects of power industry restructuring on the competitiveness of the market. Potential changes in marginal costs of generation, weighted by demand segment (e.g., peak load or base load), are assumed to be passed on to consumers, under the simplifying assumption of perfectly inelastic demand for electricity and a competitive market. This simplified estimate is used to provide an upper bound estimate of potential price increases. EPA recognizes that there will be price elasticity of demand effects, such that the quantity demanded will respond to price changes in both the short and long run. This elasticity of demand will limit the increase in prices. It is recognized, however, that these assumptions may not hold at all times and in all States.

4.5.3 Assessment of Potential for Closures and Additions

The chance that power plants might close as a result of the final section 126 rule is assessed using IPM, which determines whether it is more cost-effective to control the emissions from a given plant, buy allowances and continue to operate it, or close it down. IPM is also used to project capacity additions, based on the costs of building new capacity in comparison to its value.

4.6 Indirect Economic Impacts

The economic effects of the final section 126 rule can be transmitted through market interactions to entities that are not directly affected by its provisions. These potential indirect effects were analyzed using estimated changes in electricity rates, emission control technology, and fuel use for the NOx SIP call and were not re-estimated. Based on the similarity in magnitude of the cost increase per kwh, the effects of the final section 126 rulemaking are likely to be very close to those found in earlier analysis. The effect of rising electricity rates is assessed by multiplying the per-kilowatt-hour increase by the number of kilowatts used by typical manufacturers or consumers, and comparing this increased cost to revenues or incomes. Data are obtained from the Census of Manufacturers, Bureau of the Census, and surveys by the U.S. Energy Information Administration. Potential cost increases are assessed both in terms of nationwide averages and sensitive subgroups (including energy-intensive industries and low-income households).

Potential impacts on employment in the industries providing fuel and pollution control equipment were assessed for the SIP call by measuring changes in fuel and control equipment purchases in combination with projected labor productivity in these industries. The analysis of effects on the pollution control industry has been updated, while the fuel sector analysis has not.

4.7 Limitations of the Analysis

This analysis incorporates a fine-grained representation of the behavior of a large number of industrial entities; it covers both a long period of time and a wide geographical area. As with any similar attempt to project the future in detail, it is subject to limitations and uncertainties. Thus, several factors could lead to cost and emissions impacts above or below the reported impacts. Those factors include the following:

- **Speed of Deregulation** - EPA has assumed that electric utility deregulation will continue to move ahead at a steady pace. The Agency has also assumed that deregulation will affect the electricity market in specific ways including lower cost of transmission, higher coal plant availability, and lower reserve margins. Should deregulation occur more quickly or more slowly than assumed, or affect the electricity system in different ways, the estimated costs and emissions impacts for these regulatory options may differ.

- **Pollution Control Costs and Performance** - EPA has used estimates of pollution control costs and performance that reflect the current state-of-the-art. However, technological progress stimulated by competition could lead to improvements in the performance and cost of pollution control technology in the future. For this reason, the Agency's estimates of future cost impacts for the regulatory options considered could be overstated.

- **Regulatory Program Implementation** - EPA has assumed that the regulatory program resulting from the final section 126 rule will be implemented smoothly and at specific points in time.

- **Data Limitations** - EPA has constructed a database for this analysis that consists of information on virtually every boiler and generator in the U.S. The Agency has assembled the best information on each boiler and generator that is publicly available. Inevitably, when working with information on such a large number of facilities, some units may not be represented correctly. Improvements to the database could lead to changes in estimates of emissions and potential cost impacts for the regulatory options analyzed.

- **Analytical Limitations** - Not all analyses conducted for the NOx SIP call could be redone for the final section 126 rulemaking given time constraints, and the effects of allowance allocation systems have not been incorporated.

4.8 References

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Chapter 5. Methodology For Estimating Emission Reductions, Costs And Economic Impacts For Non-Electricity Generating Units

This chapter describes the methodologies used to estimated emission reductions, costs and economic impacts for stationary sources other than electricity generating units (EGUs) that are affected by the final Section 126 rule. These stationary sources are industrial boilers and combustion turbines. Section 5.1 provides an analytical overview for the methodologies described in this chapter. Section 5.2 describes the available NOx control technologies for industrial boilers and combustion turbines. Section 5.3 presents information on control costs and describes the cost-effectiveness methodology, and Section 5.4 discusses administrative costs associated with the final Section 126 rule. Section 5.5 provides an overview of the economic impact analysis methodology and data sources used to conduct such an analysis, and Section 5.6 discusses the methodology for estimating small entity impacts. Finally, Section 5.7 provides references for the chapter.

This chapter provides methodologies to estimate results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). This final notice presented the Section 126 remedy (0.15 trading - utilities; 60% control - industrial boilers and combustion turbines). Results from application of these methodologies take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999. In addition, these results also take into account the narrowed geographic scope of sources affected by the Section 126 remedy as a result of EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS.

5.1 Analytical Overview

The basic approach to estimating the potential effects of the final Section 126 rule on industrial boilers and combustion turbines is to project their actions in the absence of the rule; project their actions if they were subject to the rule; and then compare the two sets of actions. The actions of of these sources in the absence of the rule is referred to as the 2007 CAAA baseline, or 2007 base case. Total annual compliance costs and NOx emissions changes are estimated incremental to this base case.

The geographic scope of these analyses is the 13 jurisdictions affected by the final Section 126 rule (listed in Chapter 1). The analyses for non-EGU sources provide results for 2007, a year for which all required emissions reduction strategies are to be fully implemented. All results are presented in 1990 dollars.[1]

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[1] Results are summarized in 1997 dollars in the beginning of Chapter 7 and 9 to allow for comparisons between these results to the costs for the proposed and final Tier 2 rules and the prospective Section 812 study.

The potential emission reductions and control costs to industrial boilers and combustion turbines affected by the final Section 126 rule are estimated using a model that is primarily based on data and assumptions from Alternative Control Technology (ACT) documents prepared by EPA for many of the industries in this source categories that are affected by the rule. The costs for selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) control applications to industrial boilers are derived from a separate study that also serves as the basis for the cost estimates used in the Integrated Planning Model (IPM) for utility boilers (Bechtel, 1996). For sources identified in the NOx Budget Trading Program (industrial boilers and combustion turbines), this model estimates emission reductions and control costs for 2007 using a least-cost approach applied across the entire 13 jurisdiction region. The least cost approach used for the sources provides a proxy for State-level emissions trading programs free of transactions costs. For process heaters, a source category not identified in the NOx Budget Trading Program, a more conventional source category-specific cost analysis was conducted for the final NOx SIP call analysis and is referenced in this report. In that analysis, regulatory alternatives that place a limit on the annual cost per ton of emission reduction are examined, and the most effective NOx control technique that has an annual cost per ton below that limit is selected for each source. The annual cost per ton reduction for these control techniques is then multiplied by the difference between the 2007 baseline and controlled emissions, to estimate total annual costs for each source (U.S. EPA, 1998b).

The least-cost analyses are performed for 4 different regulatory alternatives, and the analysis for process heaters is performed for 5 different regulatory alternatives. More detail on the control technologies used to provide emission reductions are in Section 5.2 below and in the *Final Section 126 Petition Rulemaking Non-Electricity Generating Unit Cost Analysis (*Abt, 1999). Also, more detail on the control cost model operates is provided in Section 5.3 below, in the cost report previously mentioned, and in Volume 1 of the Final NOx SIP call RIA completed last year (U.S. EPA, 1998a).

Monitoring and administrative (record keeping and reporting) costs are also estimated for affected industrial boilers and combustion turbines and are added to the control costs to provide an estimate of total compliance costs. More detail on how these costs are estimated is provided in Section 5.4 below and in *Support for Revising ICR for Reporting Requirements for NOx SIP call* (U.S. EPA, 1998b).

Finally, the total compliance costs at the source level are aggregated to the establishment or plant level and further aggregated to the entity level, and are used to estimate the potential economic impacts associated with the entities directly affected by the final Section126 rule. These analyses consist of estimating compliance costs as a percentage of sales or revenues for affected entities. The Agency also conducted analyses for the set of potentially affected small entities (using SBA size definitions). More detail on how these impacts are estimated is provided in Section 5.5 and Section 5.6 below and in the *Non-Electricity Generating Unit Economic Impact Analysis for the Final Section 126 Petition Rulemaking (*Abt, 1999).

5.2 NOx Control Technology

This section describes available technologies for controlling emissions of NOx for industrial, commercial and institutional (ICI) boilers[2] combustion and turbines (Section 5.2.1).

In general, low-NOx burners (LNB) is applied as the most appropriate control technology for industrial boilers and turbines due to its possible application to most any industrial burner application (Pechan-Avanti, 1999). Other issues involved in choosing a control technology include ease of retrofit and reduction performance. While all controls presented in this analysis are considered, in general, technically-feasible for each class of sources, source-specific cases may exist where a control technology is in fact not technically-feasible. In their implementation of the final Section 126 rule, affected States may wish to consider case-specific feasibility as they revise their State Implementation Plans (SIPs) to meet the Federally-imposed requirements in this final rule.

5.2.1 NOx Control Technology for Industrial Boilers and Turbines

There are three types of control technologies considered for industrial boilers: SCR; SNCR; and low-NOx burners (LNB). As stated above, the most appropriate control technology chosen was LNB due to its breadth of application. In some cases, LNB accompanied by flue gas reburning (FGR) is applicable; such as when fuel-borne NOx emissions are expected to be of greater importance than thermal NOx emissions. When circumstances suggest that combustion controls do not make sense as a control technology (e.g., sintering processes, coke oven batteries), SNCR is the more appropriate choice.

Control technologies applicable to combustion turbines include: water injection (WI); steam injection; low-NOx burners; selective catalytic reduction (SCR); selective non-catalytic reduction (SNCR); and combinations of SCR with LNB, oxygen trim (OT), water injection, or steam injection. Table 5-1 lists the control technologies available for non-EGU industrial boilers and combustion turbines by type of fuel.

[2] The terms "ICI boiler" and "industrial boiler" are used interchangeably in this RIA.

Table 5-1
Available NOx Control Technologies for Stationary Industrial Boiler and Combustion Turbine Sources

Source Type/Fuel Type	Available Control Technology
ICI Boilers - Coal/Wall	SNCR, LNB, SCR
ICI Boilers - Coal/FBC	SNCR - Urea
ICI Boilers - Coal/Stoker	SNCR
ICI Boilers - Coal/Cyclone	SNCR, Coal Reburn, NGR, SCR
ICI Boilers - Residual Oil	LNB, SNCR, LNB + FGR, SCR
ICI Boilers - Distillate Oil	LNB, SNCR, LNB + FGR, SCR
ICI Boilers - Natural Gas	LNB, SNCR, LNB + FGR, OT + WI, SCR
ICI Boilers - Process Gas	LNB, LNB + FGR, OT + WI, SCR
ICI Boilers - Coke	SNCR, LNB, SCR
ICI Boilers - LPG	LNB, SNCR, LNB + FGR, SCR
Combustion Turbines - Oil	Water Injection, SCR + Water Injection
Combustion Turbines - Natural Gas	Water Injection, Steam Injection, LNB, SCR + LNB, SCR + Steam Injection, SCR + Water Injection
Combustion Turbines - Jet Fuel	Water Injection, SCR + Water Injection

Source: Pechan-Avanti Group, 1999.
Note: FGR = flue gas recirculation; NGR = natural gas reburn; FBC = fluidized bed circulation

5.3 Control Costs and Cost Effectiveness Methodology

This section describes the methods used to develop estimates of costs by control technology and by source category. This section also describes the approaches used for each group of sources to assign control technologies to specific source categories named in the petitions submitted to the Agency.

Two types of costs will be incurred in association with the addition of NOx control technologies: a one-time capital cost for new equipment installation, and increased annual operating and maintenance costs. In general, economies of scale exist for pollution control technologies for both capital costs and operating and maintenance costs. Thus, the size of the unit to which controls are applied will determine, in part, the cost of implementing the pollution control(s) per ton of NOx removed.

Control cost estimates by source size are developed using EPA's Alternative Control Techniques (ACT) Documents for each source category.[3] Additional control cost equations for SCR and SNCR are adapted from information originally developed for electricity generating unit (EGU) sources for use in the IPM analysis (Pechan, 1999). All costs are converted from the original source year to 1997 dollars using the Gross Domestic Product (GDP) implicit price deflator. Capital costs are annualized using a seven percent interest rate and an equipment life appropriate for each control technique, as specified in the relevant ACT Documents and other reports upon which these costs are based. Table 5-2 lists the equipment life assumptions used in this analysis. To take account of the effects of size on costs, cost equations are applied to estimate costs as a function of boiler design capacity. Engineering judgement and knowledge of the affected industries was used to assign control cost equations to specific source types (Pechan-Avanti, 1999)

Table 5-2
Equipment Life for Various Non-EGU Control Technologies

Source Category/Control Technology	Equipment Life (Years)
ICI Boilers (All fuels)	
LNB, LNB + FGR, OT + Water Injection	10
Coal Reburn, NGR	20
SCR, SNCR	20
Combustion Turbines (All fuels)	
All Controls	10

Sources may be controlled or uncontrolled in the 2007 baseline. Controlled NOx sources tend to be those in ozone nonattainment areas, or in the Northeast ozone transport region, that are subject to RACT regulations. The cost analysis takes into account these baseline controls. Where sources are uncontrolled, all available controls are considered. For controlled sources, only those control alternatives that provide NOx emission reductions beyond the baseline level of control are considered. In all cases the allocation of controls across sources is based on the total annual costs per ton of NOx reduced in the ozone season for different controls.[4]

A least-cost analysis is conducted for the non-EGUs affected in the final Section 126 rule. A NOx emissions budget for the collection of large industrial boilers and combustion turbines is

[3] The ACT Documents did not provide total O&M costs for combustion turbines. The total was calculated by subtracting the annualized capital from the total annual cost. This adds some uncertainty to the non-EGU cost estimates for combustion turbines, as both capital and total annual costs were rounded to the nearest thousand dollars in the ACT documents.

[4] Total annual cost is the sum of annualized capital costs and annual operating and maintenance costs.

established at different levels of stringency. The least costly controls, in terms of total annual cost per ozone season ton removed, across the entire set of possible source-control measure combinations are selected in order until the required NOx emission budget is achieved. Costs used in the least-cost modeling are based on source capacity since capacity data is available for the affected sources.

5.4 Administrative Costs for Industrial Boilers and Turbines

In addition to control costs, potentially affected sources could incur administrative costs associated with the collection and reporting of NOx emissions data. Estimates are developed of the administrative costs for requirements beyond those that exist in the baseline. The additional requirements include one-time activities and annual activities.

The one-time activity for an industry source to read and interpret the reporting requirements of the rule is estimated to be 1 hour for technical staff and 1 hour for managerial staff. The effort to revise a Title V permit to incorporate NOx monitoring requirements of the final rule is estimated to be 0.8 hours of technical staff (i.e., 4 hours annualized over 5-years).

Industry burden items, based on estimated annual activity, that are associated with the collection and reporting of data include a requirement to submit a year-end compliance certification report. The burden associated with this activity is estimated to be 2 hours of technical staff time, and 0.5 hour of managerial staff time for these affected sources.

Owners of sources will incur some administrative costs associated with participating in the trading system. Chapter 4 (Section 4.4) provides information on the administrative costs associated with trading for EGUs. These same costs apply to industrial boilers and combustion turbines that participate in the trading program, and these cost estimates are given in Chapter 8 (Section 8.3).

5.5 Economic Impact Analysis

This section describes the methodology used to estimate economic impacts for establishments and firms that are directly affected by the final Section 126 rule. These are distinguished from indirect impacts, which are impacts on related parties -- suppliers (including the pollution control industry), customers, or competitors of the potentially directly affected establishments -- that result from the rule. Indirect impacts would also include impacts on local taxpayers where sources subject to increased costs are owned by local governments (e.g., schools or municipal combustion units).

5.5.1 Overview of the Economic Impact Analysis Methodology[5]

Consistent with the analysis of the electric power industry described in Chapter 4, this analysis examines the economic impacts of incremental costs incurred by affected sources in the year 2007. No attempt is made to forecast changes in economic conditions between 1995 and 2007, however. The financial characteristics of the establishments and firms affected by the rule are assumed to remain the same as reported in 1995 (the latest year for which Census data are currently available.) To provide results in units comparable to the cost analyses prepared for the final NOx SIP call RIA, costs are expressed in 1990 dollars. Therefore, the 1995 financial data used to assess economic impacts are adjusted to 1990 dollars using the overall GDP implicit price deflator.[6] Costs are summarized in the beginning of Chapter 7 in 1997 dollars as well as 1990, however, to allow for ease of comparison to the costs of the final Tier 2 rule and the prospective Section 812 study. The appropriate deflator to adjust from 1990 to 1997 dollar costs is 1.231.

Several industries and other sectors (e.g., schools, colleges, hospitals and governments) are potentially subject to new controls as a result of the final Section 126 rule. Based on the control scenarios that are used by EPA to develop the State emissions budgets under this rule, the economic impact analysis for non-EGU sources relies on a screening analysis to focus on the sectors that may potentially experience impacts. More detailed analysis of market-level impacts and indirect impacts is needed only if the screening analysis shows that a substantial number of establishments in any industry might be subject to significant impacts. The more detailed market-level analysis would assess the distribution of impacts among subsectors of the affected industry and their suppliers, customers and competitors.

Potential economic impacts are assessed at both the plant (or establishment or facility) and firm level. Impacts at the plant, facility or establishment level are relevant for assessing the potential for plant closures, and to calculate aggregate impacts for specific industries.[7] Impacts at the firm-level are evaluated to determine whether small entities may be significantly impacted as part of the illustrative implementation scenario, and to determine whether the combined effect of requirements at multiple establishments owned by the same firm would impose a significant burden at the firm level.

[5] A more detailed explanation of the methods and results for the economic impact analysis of non-EGU sources can be found in Abt, 1999.

[6] Note that the adjusted data represent 1995 economic conditions expressed in 1997 dollars.

[7] The terms plant, facility and establishment are used interchangeably to refer to a single location, which may include one or more emission sources subject to additional requirements under this final rule. Costs estimated at the source level are aggregated to the facility level to provide the required inputs for the economic impact analysis. In addition, a single firm may own multiple plants or establishments. Firm-level analysis requires aggregating costs for multiple establishments owned by the same parent firm.

The screening analysis is based on the ratio of total annual compliance costs to annual sales (for businesses) or other measures of revenues or receipts (for non-profits or governments). Two screening thresholds are used: one percent and three percent. Where total annual costs represent less than one percent of annual sales or revenues, it is assumed that the rule will not cause significant burdens to the establishment or firm in question. Establishments or firms that are predicted to incur costs of three percent or more of sales or revenues are assumed to be potential candidates for significant impacts under our illustrative implementation scenario. Cases where annual costs equal between one and three percent of sales/receipts are borderline cases. In an industry that operates with low profit margins, costs of this magnitude could represent an economic burden, while in higher-margin industries this level of costs would not impose significant impacts.

The screening analysis does not indicate which establishments or firms will in fact experience significant economic burdens as a result of the final Section 126 rule, since the affected firms may be able to recover some of the added costs by increasing prices to customers. This outcome is more likely where a substantial number of firms in a given industry sector are affected and less likely if only a few firms in an industry sector incur costs.[8] A detailed market-level analysis would be required to determine to what extent firms would be able to recover costs through price increases. The screening analysis makes a worst-case assumption about impacts on profits — that all costs are borne by the directly-affected firms, and no costs are recovered through price increases.

The screening analysis can therefore be used to identify establishments, firms, and industries which can safely be assumed not to experience significant impacts and highlight other cases for more detailed investigation. The results may help States decide how to implement the requirements upon the named source categories in ways that limit the most significant impacts identified in the screening analysis.

5.5.2 Data Sources

The screening analysis relies on Dun & Bradstreet (D&B) data, where available, to determine the size of individual affected establishments and the entities that own them. D&B DUNS identifiers are collected for as many of the potentially affected establishments as possible using EPA's FINDS (the Facility Indexing System) (EPA, 1998) and Toxic Release Inventory (TRI) (EPA, 1995) databases. A D&B record for each potentially affected establishment is then accessed to identify the firm that owns the establishment (the D&B "ultimate"). The D&B record

[8] In the latter case, the affected firms would most likely not be able to raise their prices to recover costs because of competition from firms that do not incur the added costs.

also provided estimates of employment at the potentially affected establishment ("employment here") and employment and sales at the ultimate firm level.[9]

The D&B employment data are used for two purposes:

- To classify the firms owning potentially affected establishments as small or large, for those firms in industries for which the SBA small-firm criteria are expressed in numbers of employees;

- To determine the size category for each potentially affected establishment, so that the appropriate Census economic data can be selected for the establishment-level impacts analysis.

The D&B "ultimate" sales data are used to assess the ratio of total annual compliance costs to sales at the firm level.

Because reliable sales or revenue data are generally not available for individual establishments, the economic impact analysis relies on Census data to estimate average SIC establishment-level sales, revenues and receipts. Census data are reported for industries defined by 4-digit SIC codes.[10] Many of the 4-digit SICs are very broad and include establishments of varying sizes and characteristics. Census data are also disaggregated by establishment- and firm-size. Where establishment employment data are available from D&B, they are used to select Census financial data for the size group as well as industry appropriate for each affected establishment.

Where D&B employment data are not available for individual establishments, Census data on the sales/revenues/receipts for the *average* establishment and for the *average small entity* (e.g., firm) in each industry (four-digit SIC) are used to screen for potentially significant impacts.

Total annual compliance costs described in Section 5.3 are before-tax costs, which is in general the appropriate measure for estimating the total social costs of the rule. To estimate economic impacts, however, the more relevant costs are after-tax costs. From the potentially affected establishment's perspective, the costs associated with the final Section 126 rule are tax-deductible, as are other business expenses. The burden of these costs is therefore shared by the affected firms and the U.S. taxpayer in the form of lost tax revenues.

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[9] In some cases, sales at the establishment level is also provided by D&B. These data often reflect sales at the firm level or some intermediate level in the firm organization, however, and were not believed to be consistent enough to be used in the analysis of economic impacts.

[10] The North American Industry Classification System (NAICS) code equivalent(s) for the affected 4-digit SIC code industries is listed in Appendix D of the *Non-Electricity Generating Unit Economic Impact Analysis of the Final Section 126 Rule,* Abt Associates, October 1999.

Fully adjusting for the tax consequences of the estimated costs would be complex, given the range of compliance options involved and the fact that some of the affected facilities are not subject to Federal corporate income taxes (e.g. government entities, non-profit hospitals and schools.) The economic impact analysis is therefore conducted using before-tax costs, which overstates impacts on establishments for which these costs are tax-deductible.

For three sectors, additional data sources are used to obtain financial data:

- For establishments owned by electric utilities (in particular, those in SICs 4911 and 4931), data are obtained from the Energy Information Administration (EIA). The EIA sources provide both total megawatt hours (MWh) generated and total sales for the parent electric utilities of the potentially affected establishments. The former are used to determine which establishments were owned by small utilities (based on the SBA threshold of 4 million MWh), and the latter is used as the measure of firm-level sales. The electric utilities for which economic impacts are estimated are typically cogenerators (firms with establishments that do not distribute more than 50 percent of their power generation to the power grid).

- For colleges and universities, data on revenues (tuition and fees) are obtained from the National Center for Education and Statistics.[11]

- For government-owned sources, data on revenues and expenditures are obtained from the Census of Governments.

Census data are obtained from the Department of Census' Statistics of U.S. Businesses and the various 1992 Economic Censuses. Data on sales (value of shipments, receipts or revenues, depending on the sector) for the appropriate SIC and size category are divided by the number of establishments or firms, to provide the average sales/revenues/receipts per establishment or firm.

5.6 Small Entity Economic Impacts

A small entities impact analysis is required to comply with requirements of the Regulatory Flexibility Act (RFA) , as described in Chapter 1. The analysis is designed to determine whether EPA can certify that the final Section 126 rule, will not impose "significant impacts on a substantial number of small entities." EPA has evaluated the potential impacts of the rule on small entities since this rule is subject to RFA requirements. EPA has already produced a Final Regulatory Flexibility Analysis (FRFA) for the May 25 NFR referred to on page 1 of this chapter. The impacts included in the FRFA were based on the impacts estimated for the Initial Regulatory

[11] This measure of financial strength is used rather than a broader measure—which includes income from endowments—to provide a conservative screen for potential impacts.

Flexibility Analysis (IRFA) prepared for the proposed section 126 rule in September, 1998. The small entities impact analysis presented for this final rule is intended to update the estimates the small entity impacts given the changes in the NOx emissions inventory in response to the inventory correction notices issued in January, 1999 and May, 1999 and the scope of geographic coverage from the proposed rule.

The screening analysis described in Section 5.5 provides the information needed to assess whether the final Section 126 rule might impose a significant impact on a substantial number of small entities. For businesses, the D&B data on firm-level employment and revenues are compared with the SBA size standards to determine which establishments are owned by small entities. Additional data are collected to characterize the size of affected non-federal government, utility, and college and university entities, as described previously.

Once it is determined which establishments are small using the SBA definitions, the firm-level screening analysis results are used to screen for potential small entity impacts. The results of this screening analysis for sources other than electricity generating sources are combined with the results of the small entity analysis for electric utilities (described in Chapter 4) to provide an assessment of potential small entity impacts for the rule as a whole. The results of the combined small entity analysis are provided in Chapter 9.

5.7 References

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Chapter 6. Results Of Cost, Emissions, And Economic Impact Analyses For The Electric Power Industry

This chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999. In addition, the results take into account the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS. It should be noted that the results primarily reflect application of the final Section 126 remedy to all sources in a named source category in each State in the final Section 126 region. Costs are expressed in 1997 dollars along with the equivalent in 1990 dollars where appropriate.

This chapter summarizes the potential cost, NOx emission reductions, and economic impacts associated with the final Section 126 rule for electricity generating sources. The results of various regulatory alternatives are presented and compared with each other and with one of two baselines. Section 6.1 presents a summary of the chapter results. Section 6.2 introduces the annual cost and emission measures and compares four regulatory alternatives (based on NOx emission rates of 0.25, 0.20, 0.15, and 0.12 lbs/mmBtu) to the Initial Base Case. Section 6.3 presents the results of an analysis of alternative program designs and sensitivity analyses, in which the results for the 0.15 alternative are shown under various alternative assumptions regarding electricity demand, equipment life, control measure effectiveness, and the discount rate. The sensitivity analyses were conducted for the NOx SIP call and were not updated for the final Section 126 rule. As discussed in the Section 6.3, sensitivity analyses for the final Section 126 rule should show similar results. The results from the NOx SIP call analysis are presented for illustrative purposes. Potential direct and indirect economic impacts of the rule are discussed in Sections 6.4 and 6.5 of this chapter, respectively. Section 6.6 presents administrative costs and Section 6.7 contains references for the chapter.

The comparisons between alternatives, comparisons between program designs, and the sensitivity analyses are made in reference to the 0.15 lb/mmBtu alternative because that alternative is the basis for the final Section 126 rule emissions budgets. For most of the comparisons, results are presented only for the year 2007. Limiting the presentation to a single year simplifies the exposition, and the similarity in costs and emission reductions from year to year ensures that little is lost by the simplification. The year 2007 is selected in part because many areas of the affected region are obligated to reach compliance with the one-hour ozone standard in that year.

6.1 Results in Brief

The NOx emissions reductions for EGUs in 2007 expected across the spectrum of regulatory alternatives examined in this chapter ranges from 384,000 tons to 679,000 tons. For the final EGU alternatives (0.15 trading), the emissions reductions are estimated to be 611,000 tons. The annual compliance costs in 2007 of these EGU regulatory alternatives applied across the final Section 126 region ranges from $472 million to $1,387 million dollars in 1997 dollars (or

$393 million to $1,155 million in 1990 dollars). For the final EGU regulatory alternative (0.15 trading), the annual compliance costs in 2007 is estimated to be $1,051 million in 1997 dollars (or $875 million in 1990 dollars). The average cost-effectiveness of the EGU regulatory alternatives range from $1,228/ton to $2,043/ton in 1997 dollars ($1,023/ton to $1,701/ton in 1990 dollars). For the final EGU alternative (0.15 trading), the average cost-effectiveness of control is $1,720/ton in 1997 dollars ($1,432/ton in 1990 dollars).

6.2 Comparison of Alternatives to the Initial Base Case

EPA considered four alternatives in developing the final Section 126 rule, each one based on a different allowable emissions rate. For example, the 0.15 alternative is based on limiting summer NOx emissions to 0.15 lb/mmBtu of fuel heat input during the summer season after allowing for growth in electricity demand to 2007. This alternative imposes a seasonal cap of 340 thousand tons of NOx from EGUs in excess of 25 MW on the final Section 126 region. The 0.15 alternative provides the point of comparison for sensitivity and other analyses in this chapter. The Integrated Planning Model (IPM) was used to generate predictions of the technology selection, costs, and emissions for EGUs under the various alternatives.

Trading is assumed to be allowed both within and among the 13 jurisdictions in the final Section 126 region. EPA examines the cost and emission reduction impacts of each of the regulatory alternatives incremental to the Initial Base Case level. The Initial Base Case assumes compliance with RACT, BACT, and NSPS requirements, as well as Phase I of the Ozone Transport Commission (OTC) Memorandum of Understanding (MOU); as such it includes all currently applicable Federal or State NOx control measures. The Final Base Case assumes the controls included in the Initial Base Case, as well as Phase II and Phase III of the OTC MOU. In the Final Base Case, many units have already implemented SNCR and SCR controls to meet the more stringent requirements of the Final Base Case. This section presents the results of the cost and emissions reductions analyses and translates those results into measures of cost-effectiveness for the regulatory alternatives. Section 6.1.5 of this chapter contains a comparison of the costs of the 0.15 trading alternative in the Initial and Final Base Cases.

6.2.1 Technology Selection

Tables 6-1 and 6-2 present emission control responses for coal- and oil/gas-fired boilers in the final Section 126 region under each of the alternatives. Table 6-3 shows additions to natural gas combined cycle capacity that will occur in response to the final Section 126 rule. Industry will increase its use of natural gas over coal to generate power as part of its approach to compliance. Some coal, oil, or gas-fired boilers will be retrofit with SCR, SNCR, or gas reburn. Other units will have no incremental control technology added beyond the types of controls required under Title IV, BACT and OTC Phase I/RACT in the Initial Base Case. In addition, some boiler capacity could close in response to the final Section 126 rule. Not shown in the table are combustion turbines and combined cycle units, which are not expected to be retrofit with additional controls in response to the final Section 126 rule. IPM analysis does show, however, that about 800 to 3,500 MW of combined cycle capacity would be added nationwide, depending on the alternative. The IPM runs project that almost all of the control technology retrofits needed to reduce emissions to the cap would be among the coal-fired boilers, which tend to be both larger and higher in baseline emissions than other types. As alternatives become more stringent, Title IV controls (i.e., combustion controls such as low NOx burners) are augmented with SNCR and then with SCR (which is capable of greater NOx reduction). The same general pattern is seen for the oil/gas-fired boilers, though the percentages of them that are retrofit with SNCR or SCR are smaller than for the coal boilers.

Table 6-1
Estimated Emission Control Responses for Coal-Fired Steam Units
to the Final Section 126 Rule in 2007
(MW capacity for the section 126 region)

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Close Unit	17	34	113	113
Comply with BACT	2,712	2,712	2,712	2,712
Title IV NOx Controls Only [a]	45,853	16,781	5,409	5,209
Add SNCR	72,788	88,468	66,923	43,221
Add SCR	5,175	18,170	52,121	76,403
Add Gas Reburn	1,242	1,622	509	129
Total	127,787	127,787	127,787	127,787

Source: ICF analysis.
[a] This row shows the MW capacity adding *only* Title IV NOx controls for Title IV as well as for section 126. Therefore, the numbers tend to decrease with increases in option stringency.

Table 6-2
Estimated Emission Control Responses for Oil/Gas-Fired Steam Units
to the Final Section 126 Rule in 2007
(MW capacity for the section 126 region)

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Close Unit	139	193	213	326
No Further Controls Beyond OTC Phase I/RACT	24,255	24,002	23,235	17,908
Add SNCR	0	199	946	5,420
Add SCR	0	0	0	740
Total	24,394	24,394	24,394	24,394

Source: ICF analysis.

Table 6-3
Estimated Emission Control Responses to the Final Section 126 Rule in 2007
Added Natural Gas Combined-Cycle
(MW capacity nationwide)

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Added Capacity of Combined Cycle[a]	803	1,308	1,671	3,517

Source: ICF analysis.
[a] Above level in the Initial Base Case, which is 47,308 MW, nationwide.

6.2.2 Emissions

The control technologies presented in Tables 6-1 and 6-2 will reduce annual NOx emissions by hundreds of thousands of tons in the final Section 126 region. Although the final Section 126 rule focuses on ozone season NOx emissions, reductions of NOx emissions under the alternatives will occur year-round because some of the control strategies (e.g., combustion controls) function continuously. For the 0.15 alternative in 2007, the annual reductions amount to 725 thousand tons relative to the Initial Base Case, with 114 thousand of those tons (16 percent) from outside the ozone season. Table 6-4 shows the ozone season tons of NOx emitted under each of the alternatives compared to the Initial Base Case. The rule requires sources to be in compliance starting in May 2003. From that point on, the emissions for electricity generating units are assumed to be capped under the scenarios modeled by EPA, resulting in emissions of 340 thousand tons of NOx per ozone season under the 0.15 alternative. Initial Base Case emissions continue to increase after this point due to forecasted growth in electric power generation, while the cap remains constant. As a result, the incremental NOx emission reductions grow yearly after 2003. Figure 6-1 shows State-by-State budgets under the four alternatives.[1] Figure 6-2 shows the emissions for the Initial Base Case, the State budget levels, and the IPM analysis results for the 0.15 alternative.[2] The incremental reduction in ozone season tons under the 0.15 alternative amounts to about 65 percent of baseline ozone season NOx emissions in the period between 2003 and 2010, with a slightly lower percentage reduction in the early years of the program. By contrast, the reductions in annual tons are less than 35 percent of baseline annual tons, because emission reductions in the non-ozone season are only about 9 percent of baseline emissions in those months. This disparity stems from the fact that the most widely used control strategies — SNCR and SCR — can be shut off at the end of each ozone season to limit operating costs. Most importantly, as Figure 6-2 shows, a trading program can lead to reductions throughout the final Section 126 region that are comparable to what would occur under a command-and-control approach where States set emission rates for EGUs aimed at hitting each State's NOx budget level.

[1] The data used to develop Figure 6-3 is included in Appendix C, Table C-1.

[2] The data used to develop Figure 6-4 is included in Appendix C, Table C-2.

Table 6-4
Estimated Ozone Season NOx Emissions and Reductions under the Policy Alternatives and the Initial Base Case
(1,000 ozone season tons)

Case/Alternative	2003	2005	2007	2010
Initial Base Case	921	943	951	958
0.25 Alternative (Reduction)	566 (355)	566 (376)	566 (384)	566 (392)
0.20 Alternative (Reduction)	453 (468)	453 (489)	453 (498)	453 (505)
0.15 Alternative (Reduction)	340 (582)	340 (603)	340 (611)	340 (619)
0.12 Alternative (Reduction)	272 (649)	272 (671)	272 (679)	272 (686)

Source: ICF analysis.

Figure 6-1
Ozone Season NOx Budgets in 2007 from the Electric Power Industry for States in the Section 126 Region

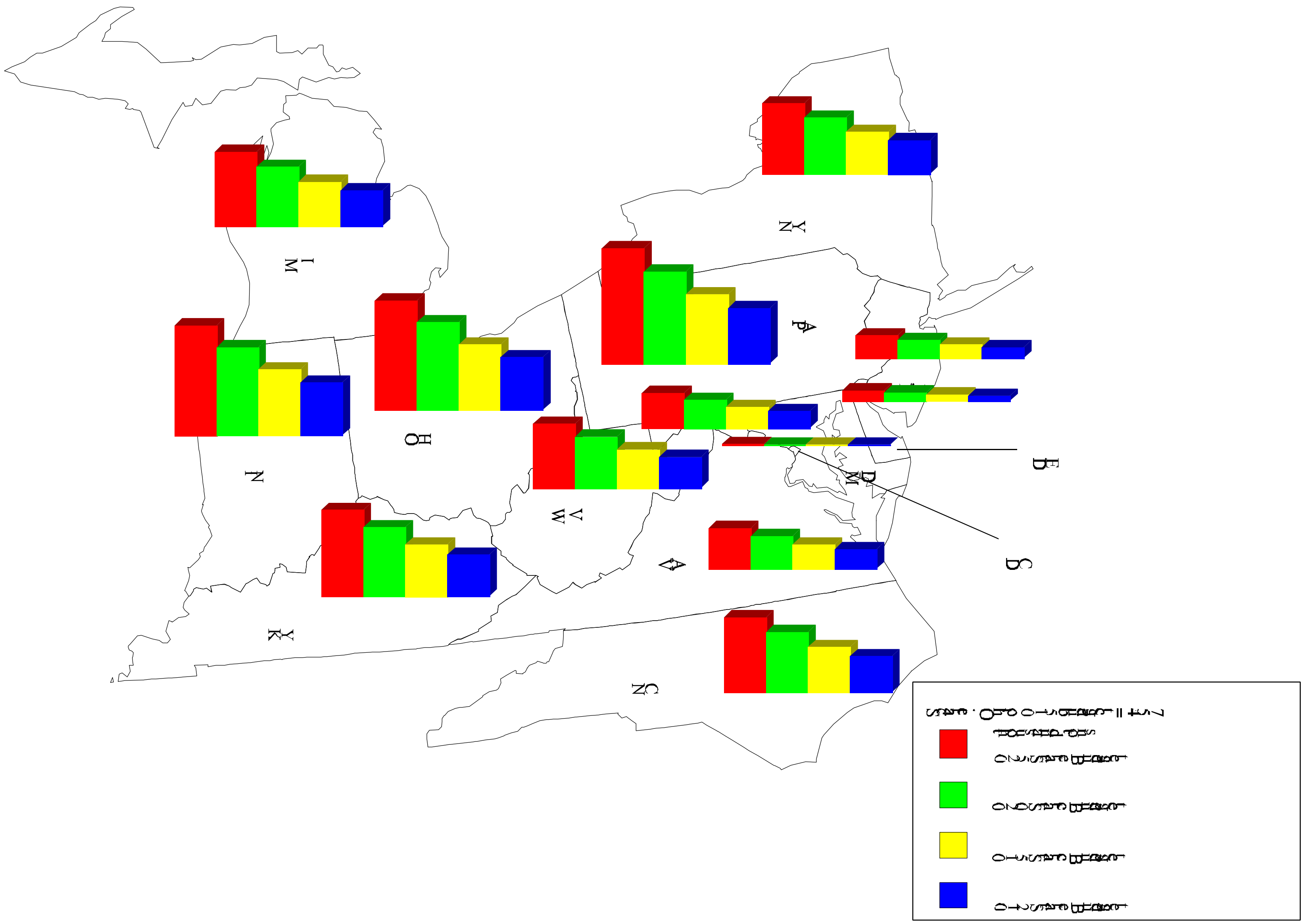
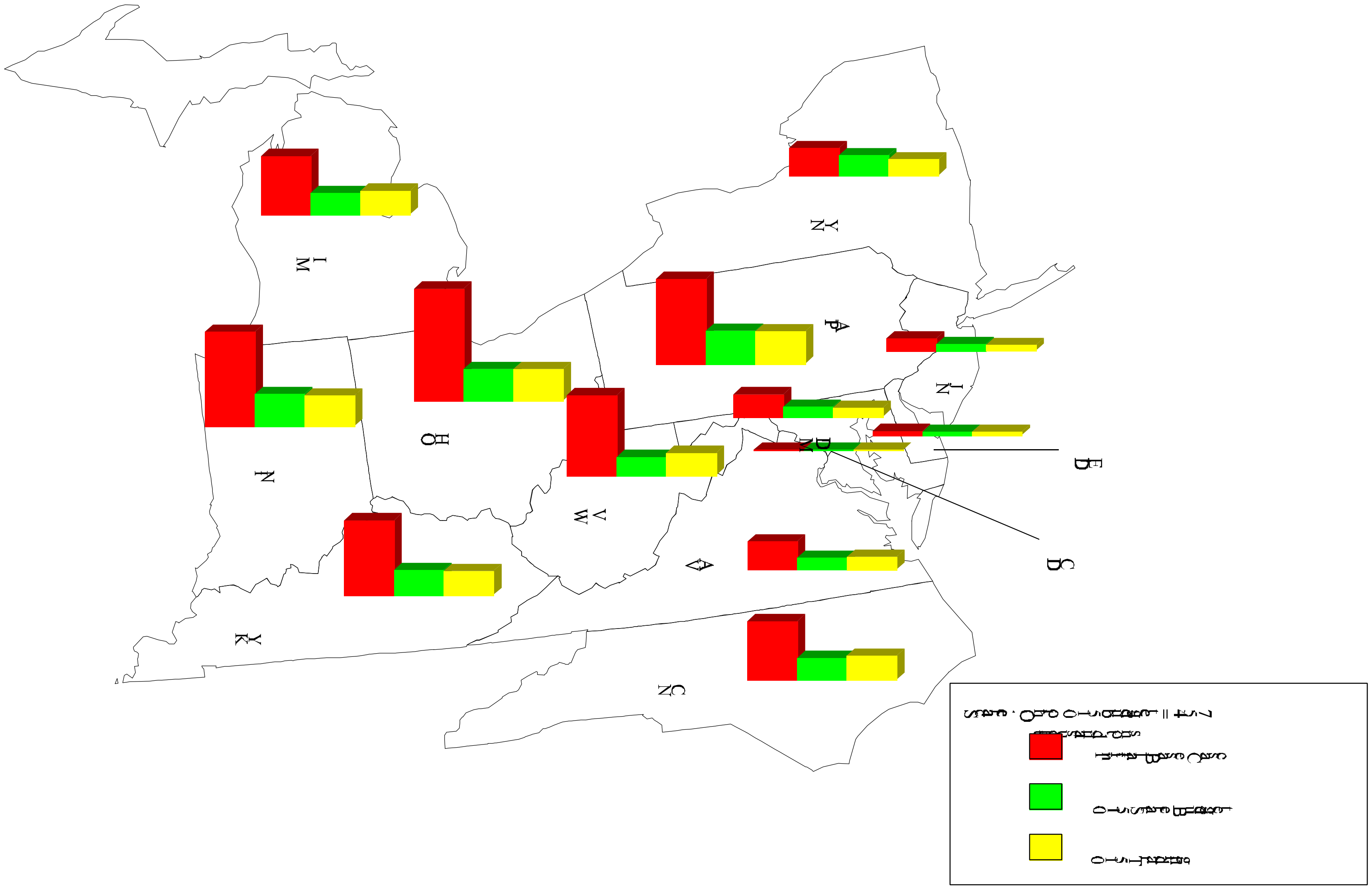


Figure 6-2
Ozone Season NOx Emissions in 2007 from the Electric Power Industry for States in the Section 126 Region:
0.15 Trading Alternative Compared to the Initial Base Case and the State Budget Component under the 0.15 lb/mmBtu Limit



6.2.3 Costs

EPA calculated the annual cost of the alternatives incremental to the Initial Base Case level.[3] Table 6-5 presents EPA's estimates of the total annual costs that the electric power industry could incur in the years 2003, 2005, 2007, and 2010. Because of growth in demand for electricity, the fixed cap of 340 thousand tons per ozone season becomes progressively tighter over time; as fuel input grows, the fixed allocation of allowances leads to a tighter and tighter effective limit. This effective tightening tends to drive the costs of meeting the emissions cap higher over time. Countering this tendency, on the other hand, is a reduction over time in the costs of new generation and control technologies, and the possibility of retrofitting existing plants to function as combined-cycle units.

Table 6-5
Incremental Annual Costs for Alternatives Relative to the Initial Base Case
(Compliance costs above Initial Base Case, million 1990$)[a]

Alternative	2003	2005	2007	2010
0.25 Trading	$387	$408	$393	$432
0.20 Trading	$586	$600	$591	$621
0.15 Trading	$847	$886	$875	$914
0.12 Trading	$1,114	$1,146	$1,155	$1,155

Source: ICF analysis.
[a] Compliance costs do not include administrative, monitoring, or transaction costs, which are minor in comparison to the total cost of the rule. Units covered by Title IV will have monitoring devices in the baseline, which will reduce the incremental monitoring costs. See Section 6.5.

Trading

Some regulated sources have years of experience with inter-firm and intra-firm emissions trading. In the mid-1980s, EPA published the Emissions Trading Policy Statement (51 FR 43831), which allowed sources to obtain emission credits for use as emission offsets and in bubbles. In 1990, the Clean Air Act Amendments (CAAA) expanded the potential pool of sources that would need to obtain offsets. The 1990 CAAA was also the advent of the acid rain SO_2 allowance market, under which the electric power industry learned to use emissions trading as a compliance strategy. In addition, a variety of market-based programs have been implemented at the State and local levels. Most recently, the Ozone Transport Commission (OTC) adopted a Memorandum of Understanding committing the signatory States to the development and proposal of a regional NOx emissions cap-and-trade program, similar to the one proposed under the final Section 126 rule. Currently, eight States (Connecticut, Delaware, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island) are participating in the OTC trading program. Under these emissions trading programs, especially the allowance markets, the affected sources became familiar with emissions trading markets and the procedure for buying and selling allowances.

Table 6-6 shows the number of expected trades for individual units, including inter- and

[3] All cost data and cost-effectiveness calculations are presented in 1990 dollars.

intra-firm transactions, under the 0.15 trading alternative. It is notable that a substantial number of trades could occur under this alternative, with many units able to generate excess allowances for the use of other units. Sources are assumed to participate in the NOx allowance market to utilize the most cost-effective compliance option and because of experience gained with other trading programs. The potentially affected sources are expected to trade allowances within their own company and/or with other companies. For example, based on the IPM results for the 0.15 alternative, 383 units are projected to obtain about 45,000 allowances from the 294 units projected to provide excess allowances. Only 27 percent of the units (254 units) are expected to use only the allowances allocated to them. The number of allowances traded between and within companies varies slightly under each of the alternatives. Under the 0.15 alternative, about 19,000 of the 45,000 traded allowances (over 40 percent) are projected to be inter-firm trades.[4] Though EPA has estimated the volumes of inter-firm allowance trades only for the 0.15 alternative, the number of allowances traded among individual firms may vary from alternative to alternative.

Table 6-6
Number of Fossil Fuel-Fired Units in IPM Runs
Expected to Buy, Sell, or Make No Trades (Do Nothing) in the Section 126 Rule Trading Program[a]
(0.15 Alternative)

Fuel Type	Buy Allowances	Sell Allowances	No Trades (Do Nothing)
Coal	308	167	0
Oil/Gas	24	56	4
Combined Cycle/ Combustion Turbine	51	70	250
Integrated Gasification/ Combined Cycle	0	1	0
Total	383	294	254

[a] Allowance transfers within companies are included among the purchases and sales, though money would not necessarily change hands in these internal transactions.

Analysis of the differences in the number of units buying and selling allowances under the 0.12, 0.15, and 0.25 alternatives was conducted for the NOx SIP call RIA. The analysis showed that there would be vigorous trading under each regulatory option, even under the most stringent cap. The analysis for the NOx SIP call demonstrated that more units would participate in allowance sales and purchases under the 0.12 alternative than under the 0.15 alternative.

6.2.4 Cost-Effectiveness

The average cost-effectiveness of the regulatory alternatives is calculated from the Initial Base Case level. Cost-effectiveness is calculated as the total annual costs of the alternative divided by ozone season emission reductions. Table 6-7 shows the emissions change and the annual costs and cost-effectiveness that EPA estimates for the potentially affected part of the electric power industry in the years 2003, 2005, 2007, and 2010. As shown in the table, the average costs per ozone season ton of NOx removed under the 0.15 alternative for each of the

[4] This total may include a small volume of trades between plants owned by the same non-utility EGUs.

four years differ slightly due to the effects of the growth in electricity demand and the application of the fixed cap of ozone season tons of NOx on cost, but for each year is less than $1,500 per ton of NOx removed.

Table 6-7
Summary of Estimated Emission Reductions, Cost, and Cost-Effectiveness for the Final Section 126 Rule

Year/Alternative	Reductions in Ozone Season NOx Emissions (1,000 tons)	Annual Cost above Initial Base Case (million 1990$)	Cost per Ozone Season Ton of NOx Removed (1990$/ton)
2003			
0.25 Trading	355	$387	$1,090
0.20 Trading	468	$586	$1,252
0.15 Trading	582	$847	$1,455
0.12 Trading	649	$1,114	$1,716
2005			
0.25 Trading	376	$408	$1,085
0.20 Trading	489	$600	$1,227
0.15 Trading	603	$886	$1,469
0.12 Trading	671	$1,146	$1,708
2007			
0.25 Trading	384	$393	$1,023
0.20 Trading	498	$591	$1,187
0.15 Trading	611	$875	$1,432
0.12 Trading	679	$1,155	$1,701
2010			
0.25 Trading	392	$432	$1,102
0.20 Trading	505	$621	$1,230
0.15 Trading	619	$914	$1,477
0.12 Trading	686	$1,155	$1,684

Source: ICF analysis.

Comparing the change in total costs to the change in emissions, it can be seen that the cost per ozone season ton removed increases with increasing alternative stringency. Thus, costs are rising faster than emission reductions, as more costly measures are pressed into service on smaller and less-intensively used units. The increasing per-ton cost can be seen more clearly by presenting the changes in costs and tons for each alternative *relative to the next-most-stringent alternative,* instead of relative to the base case. This approach, which shows the incremental per-ton costs of just the *additional* tons of reductions as the alternatives grow more stringent, is presented in Table 6-8.

Table 6-8
Comparison of Estimated 2007 Incremental Ozone Season NOx Emission Reduction, Cost, and Cost-Effectiveness for Different Regulatory Alternatives under the Final Section 126 Rule

Alternative	Reduction Incremental to Next-Most-Stringent Alternative (1,000 ozone season tons)	Cost, Incremental to Next-Most-Stringent Alternative (million 1990$)	Incremental Cost-Effectiveness, Relative to Next-Most-Stringent Alternative (1990$/ozone season ton)
0.25 Trading[a]	384	$393	$1,023
0.20 Trading	113	$197	$1,743
0.15 Trading	113	$284	$2,513
0.12 Trading	68	$281	$4,132

Source: ICF analysis.
Because of rounding, the cost-effectiveness values do not equal the ratio of the incremental costs to the NOx reductions shown in the table.
[a] Compared to the Initial Base Case.

6.3 Other Program Designs and Sensitivity to Modeling Assumptions

This section compares the major program alternatives considered by EPA in the development of the final Section 126 rule. Though most of these analyses were conducted for the NOx SIP call and not re-analyzed for the final Section 126 rule, the general effects should be consistent with the final Section 126 rule, given the similarity between Section 126 and NOx SIP call sources and the similarity between fuel mix and utilization. Section 6.3.1 contains the results of the banking/no banking analysis, and Section 6.3.2 presents IPM results for the 0.15 trading alternative under varying assumptions on technology, discount rate, and electricity demand.

6.3.1 Banking

Under an allowance-based emissions trading program with banking, sources can create reductions beyond required levels in one season, thus freeing up some allowances for use in a later season. Each banked allowance represents one ton less emissions in the current season. Banking is a cross-cutting option, because it can be used with any of the alternatives. Banking encourages early reductions, provides flexibility, and reduces cost for regulated sources. It also dispels the "use it or lose it" conception concerning the use of allowances, and accommodates changes in generation activity that may occur in response to interruptions of power supply from sources that do not emit NOx. On the other hand, banking can create uncertainty about actual emissions in a given season.

EPA considered several banking alternatives, including options with (1) no banking; (2) banking of emission reductions after the start of the program; (3) banking of "early" reductions (i.e., those that come before the beginning of the program); (4) and banking from an earlier phase of the program to a later phase.

In the RIA for the NOx SIP call, banking of "early" reductions was modeled only for the

0.15 alternative because earlier IPM analysis suggested that owners of electricity generating units would want to use it to a very limited degree to lower the costs of future compliance, although not all the important advantages of banking were incorporated into that analysis (EPA, 1997a). A two-phase banking program was not modeled. An IPM analysis was conducted for the 0.15 NOx SIP call alternative with and without banking, where banking began after the start of the program in 2003. This analysis was not updated for the final Section 126 rule. The cost and emission reduction estimates will be overstated, but the general effect is not expected to differ greatly for the final Section 126 rule given the similarity between sources and the similarity between fuel mix and utilization.

Banking is most valuable for programs in which costs per ton removed rise over time, which is most likely to occur if the effective stringency of the regulations rises over time. In the case of the NOx SIP call (and the final Section 126 rule), the effective stringency rises only slightly over time as a result of a fixed emissions cap interacting with a growing demand for electricity. Over time, however, anticipated improvements in technology (including combined-cycle retrofits) will counteract the effects of growth, so that the cost per ton removed is expected to fall eventually.

Given the fact that costs per ton removed under the NOx SIP call were expected to rise only slightly at first and then fall, it is not surprising that little banking was predicted by IPM in the 0.15 alternative when banking began in 2003. Both costs and the geographic distribution of emission reductions were almost the same with or without a banking program. The total cost of the program was 1.4 percent higher in 2003 with banking, but between 0.4 percent and 1.5 percent less costly in 2005, 2007, and 2010. Emission reductions were 0.3 percent higher in 2003 with the banking program, were slightly higher in 2005 and 2007, and were the same under the banking and no banking scenarios in 2010. The cost per ton removed follows the same pattern, with slightly higher removal costs in 2003 and slightly lower removal costs in the later years of the program.

This analysis does not consider a banking plan in which emission reductions prior to 2003 could be used to ease the transition to the requirements of the NOx SIP call (or the final Section 126 rule), and help ensure that allowances were available for planning purposes early in the compliance period. Under that type of banking program, more tons would be banked and the savings and other advantages (especially in terms of reduced uncertainty) would be greater. Annual emissions starting in 2003, however, would be higher and less predictable than in programs that did not allow early emissions to be banked.

6.3.2 Sensitivity to IPM Assumptions

In the course of the NOx SIP call regulatory analysis, sensitivity analyses on several key assumptions in the IPM analysis were conducted. The sensitivity analyses were evaluated relative to the 0.15 alternative of the NOx SIP call and have not been updated to reflect the analysis conducted for the final Section 126 rule. While the absolute cost and emission estimates have changed under the final Section 126 rule and would have changed under revised sensitivity analyses, the general responses of EGUs to each of the sensitivity analyses are expected to be consistent between the two rules because the market conditions and geographic coverage of the two rules are quite similar. The analyses were developed to assess the robustness of the results outlined above and to respond to comments, and include the effects of a higher discount rate, lower SNCR effectiveness, shorter equipment life, and higher growth rates of demand for output from fossil-fueled units. See also Chapter 6 of the NOx SIP call RIA.

Effects of Higher Discount Rate

This sensitivity analysis assumed an after-tax cost of capital of eight percent per annum rather than the six percent rate that was assumed in the rest of the IPM modeling. The incremental cost of the 0.15 alternative of the NOx SIP call rose by about 2.6 percent when a higher discount rate was assumed. Emission reductions were 0.2 percent higher under the higher discount rate assumption. The higher discount rate would have led operators to delay installing new, lower-emitting units. This delay in introducing new units would have lead to higher baseline emissions and to the need for greater reductions to reach the assigned NOx budget. The percentage increase in cost was higher than the percentage increase in reductions. Therefore, the cost per ton of summer NOx reduced increased by approximately 2.5 percent.

Effects of Lower SNCR Effectiveness

This scenario assumed that, on coal-fired boilers with baseline emissions below 0.50 lb/mmBtu, SNCR would reduce NOx by 30 percent rather than 40 percent, as assumed in the rest of the analyses. The sensitivity analysis predicted the technology choices under the expected effectiveness scenario and the lower assumed effectiveness scenario. Shifts in the application of technology took place with lower SNCR effectiveness. Less capacity was retrofitted with SNCR when a lower effectiveness was assumed (36 percent less), and more capacity was retrofitted with SCR (47 percent more). EPA examined whether this potential increase in the installation of SCR would be feasible by 2003 and found that it would be feasible (EPA, 1998a). A small increase in capacity of gas combined cycle units (three percent) was also predicted under the lower SNCR effectiveness scenario.

The emissions estimates did not change under the lower SNCR effectiveness scenario. The incremental cost of the 0.15 alternative of the NOx SIP call rose (by about 11 percent) when lower SNCR effectiveness was assumed. Costs increased because the reduced cost-effectiveness of the SNCR units required substitution of more expensive control measures.

Effects of Shorter Equipment Life

This scenario assumed that all equipment life was 15 years rather than 20 years as was assumed in the primary IPM analysis for the NOx SIP call. The changes in the technologies used to comply with the NOx SIP call or the final Section 126 rule under a shorter equipment life scenario are similar to those seen for the higher discount rate scenario: capital-intensive technologies are used less, with greater emphasis on dispatching changes. This sensitivity analysis showed that the incremental cost of the 0.15 alternative of the NOx SIP call would have risen by six percent if equipment life were shorter than assumed by EPA.

Effects of Alternative Demand Scenarios

Alternative demand scenarios were analyzed for the NOx SIP call to estimate the effects on projected cost and cost-effectiveness of changes in electricity demand forecasts, using the 0.15 trading alternative as a basis for comparison. The first alternative scenario assumed the full increase in demand projected by NERC; unlike EPA's baseline assumptions, this alternative did not allow for reductions related to the Climate Change Action Plan (CCAP).[5] The second alternative scenario assumed that retail competition (in addition to the already-assumed wholesale competition) occurred throughout the country. Three main quantitative effects of retail competition were modeled: electricity price reductions, which induce increases in electricity demand; initiation of time-of-day pricing; and increased retirement of nuclear generation units due to their inability to be competitive.

Both of these alternative demand scenarios led, in the Initial Base Case, to more electricity production from fossil-fueled units. Greater projected fossil-fueled production led, in turn, to higher emissions in the Initial Base Case, and the need for greater reductions (six percent higher under both scenarios) to meet a given emissions cap. The total cost and the cost per ton removed were therefore higher under the alternative demand scenarios. For the NERC Demand/No CCAP reduction scenario, the total compliance cost was approximately nine percent higher and the cost per ton removed was three percent higher than in the Initial Base Case. The full retail competition scenario showed an eight percent increase in total costs and a two percent increase in cost per ton removed.

6.4 Direct Economic Impacts

This section presents the results of the cost analyses from the perspective of potential economic impacts. Direct impacts, which are presented in this section, are those borne by the entities that potentially incur costs because they are required to reduce emissions. Indirect impacts, on the other hand, fall on entities that are affected through their interactions with the directly affected entities. These indirect impacts are presented in Section 6.5.

This section moves from the broadest level of impacts down to more specific assessments. Costs of the rule relative to all electricity generation are presented first, followed by consideration of the potential distribution of costs across types of generators. Finally, potential impacts on small owners of electricity generating units are summarized.

6.4.1 Costs Relative to Electricity Generation and Revenues

Table 6-9 shows the potential impact of the compliance costs of the rule at the broadest level by comparing them to the total amount of electricity generated annually. Annualized costs for the year 2007 are shown in the third row of the exhibit for four alternatives. These costs are then compared to electricity generation to show costs in terms of mills (i.e., tenths of cents) per kilowatt-hour. Also shown in the table is the fact that generation in the final Section 126 region is

[5] The CCAP reductions are listed in Chapter 4, Table 4-1.

lower under each of the alternatives than in the base case. Because power production will be growing over time with or without the final Section 126 rule, producers in the Section 126 region will still generate more power in 2007 than in the current year — the effect of the final section 126 rule will be to lower the rate of generation growth in the Section 126 region and shift some of it to nearby States where power is less expensive to produce.[6] Furthermore, because some utilities will own capacity both inside and outside of the final Section 126 region, some of the shifts in generation will represent a shift within corporations, rather than a shift in output from one group of firms to another.

Table 6-9
Generation Changes and Costs Compared to Total Generation in 2007 for Alternatives of Differing Stringency

	Initial Base Case	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Total Generation in Section 126 Region (millions MWhs for affected units)	976	946	944	942	931
Percent of National Power Generation	26%	25%	25%	25%	25%
Costs Relative to Initial Baseline (billion 1990$)	-	0.39	0.59	0.87	1.16
Average Cost per Unit (mills/kWh, 1990$)	-	0.41	0.62	0.92	1.25

Source: ICF analysis and U.S. Energy Information Administration *Annual Energy Outlook 1998*, December 1997.

These potential costs can be put into perspective by comparing them to the typical revenues received by electricity suppliers. Table 6-10 shows, for the same alternatives presented in the preceding exhibit, the incremental per-kilowatt cost of generation in comparison to an estimate of per-kilowatt-hour revenues received by utilities and other suppliers in the final Section 126 region. Revenues, in turn, closely approximate the total costs of supplying electricity to the end-use customer (including amortization of equipment and a return on invested capital).[7] Table 6-10 shows that the potential costs of the rule are less than three percent of the revenues of electricity suppliers for all of the alternatives, and climb above two percent only for the 0.12 alternative. Under traditional cost-of-service regulation, this potential cost increase could be expected to constitute the price increase as well.

[6] EPA did not analyze the potential change in electric demand (it is held constant), rather, EPA analyzed the change in the mix of suppliers that may result from implementation of the final section 126 rule.

[7] Table 6-11 shows the costs of the final Section 126 rule in 2007 in comparison to 1996 revenues from electricity. Per-unit revenues can be expected to change over time (as a result of increased competition in the industry), so the percentage impact of the rule will differ from the impact shown in the table.

Table 6-10
Final Section 126 Rule Compliance Costs by Alternative
Compared to Revenues from Electricity in 2007
(1990$)

	0.25 Trading	**0.20 Trading**	**0.15 Trading**	**0.12 Trading**
Average Per-unit Revenues, 13 Jurisdictions, Initial Base Case (mills/kWh)[a]	60	60	60	60
Cost per Unit, all Generation in Section 126 Region (mills/kWh)	0.41	0.62	0.92	1.25
Cost as a Percentage of Revenues	0.69%	1.04%	1.54%	2.08%

Source: Average revenues per kWh calculated by ICF using EIA Form 861 for 1996; other figures calculated by ICF.
[a]The table shows the costs of the final section 126 rule in 2007 in comparison to current revenues from electricity. Per-unit revenues can be expected to change over time (as a result of increased competition in the industry), so the percentage impact of the rule will differ from the impact shown in the table.

Effects of Cost Changes on Electricity Producers

Whether potential costs of the magnitude shown in Tables 6-9 and 6-10 have a significant impact on electricity producers depends in part on whether the costs will be accompanied by offsetting price changes. In the past, because the electric power industry was tightly regulated, it was reasonable to assume that their rate commissions would have approved (perhaps after a lag) rate increases sufficient to cover the costs related to emission control programs. Alternatively, part of the rule-related increases in operating costs may have been reflected in fuel adjustment clauses. The lack of competition helped to limit the reduction in demand resulting from a rate increase. Utilities could thereby expect to continue receiving an adequate return on invested capital, and concerns about economic impacts were limited to the lag between cost and rate increases, and the impacts of the rate increases on electricity demand.

More recently, the restructuring of the industry and the prospect of competition among utilities and non-utility producers has added uncertainty to the task of projecting economic impacts on utilities. Competition at the wholesale level may complicate the process of passing on unusually high costs, while greater uncertainty over the speed of retail deregulation increases the difficulty of projecting the price impact on customers. This section discusses some potential effects of the restructuring process on the recovery of the costs of the rule by electricity generators.

The potential effects of the final Section 126 rule on the electric power industry will depend in part on the timing of the rule relative to the progress of the restructuring process. The final Section 126 rule is scheduled to go into effect by mid-2003. Competition at the wholesale level is already underway and will be fully implemented prior to 2003. Competition at the retail level is expected to spread widely by 2002, and to be largely complete by 2003 to 2005 (in the States where it occurs). Thus, for most of the period in which the final Section 126 rule will impose costs, the assumptions of freely competitive markets should apply. The following discussion of effects on utilities, therefore, begins from a free-market perspective. Following that discussion, the effects of possible limits on competition early in the period are discussed.

Effects of Cost Increases Under Competition

In a world in which electricity prices are set by competitive market forces at both the wholesale and the retail level, theory predicts that the interaction of buyers and sellers will ensure that prices reflect the marginal costs of generation (that is, the incremental costs of producing another unit of output).[8] The need to limit NOx even as electricity output increases means that marginal costs of generation will rise: producing more electricity under the final Section 126 rule might require using more reagent for SNCR units as capacity factors increase, or it might require the use of higher-cost fuels than are used under the Initial Base Case. Assuming that the demand for electricity is relatively inelastic (which is a reasonable conservative assumption for the short run), the price of electricity is predicted to rise by up to the amount that marginal costs rise.[9]

Because suppliers in a competitive market are not required to produce at a loss, this increase in prices can be expected to be high enough to at least cover the *variable* costs actually incurred by every producer. Any kilowatt-hours that would have cost more to generate than the revenues they would bring in would not be produced. The fact that price will be high enough to cover variable costs, however, does not by itself mean that there would be no impacts on generators. Some generating units might have unusually high variable costs for any given level of output; such units will not be used during time periods in which the market price of electricity is too low given their variable costs. Overall, generators in the final Section 126 region are predicted to cut output during the ozone season by a percent or more, largely from power plants that would use control strategies with high marginal costs (e.g., combinations of SNCR and allowance purchases). The owners of these units will lose net revenues, due to decreased output under the final Section 126 rule.

A more significant issue is that the adjustment of prices in response to changes in marginal costs does not guarantee that all increases in fixed costs will be covered. Fixed costs (such as the capital costs of installing emission control systems) do not affect the free market equilibrium unless they are large enough to result in the retirement of plants as a way to avoid incurring unrecoverable costs. Short of early retirement, which IPM does not project for any significant amount of capacity, there is no necessary connection between fixed costs and price changes.

Some or all of the fixed costs of the rule can be recouped if the price increases exceed the average change in variable costs. A relatively large increase in marginal costs could occur, for example, if generating units that are available for generating incremental power tend to be those with high variable costs of control (e.g., those with SNCR and a need to purchase allowances for

[8] The total price of electricity to consumers includes, in addition to the costs of energy, additional costs for transmission, distribution, and (where appropriate) charges for peak capacity. In the NOx SIP call analysis, capacity charges were found not to be affected significantly under the 0.15 alternative. Transmission and distribution charges are assumed not to change in response to the final Section 126 rule. Thus, this analysis and discussion focuses on the marginal costs of producing energy, which are expected to rise as a result of the final Section 126 rule.

[9] A price increase could result in a more significant reduction in the quantity of electricity demanded in the long run than in the short run. A reduction in electricity demand would lower the total costs of the final Section 126 rule, and limit the size of the price increase, while reducing the revenues received by electricity producers. These possible impacts have not been analyzed for this report.

every additional mmBtu of fuel used). Because the change in the price of electricity will be determined by the increase in marginal costs for these marginal units, the price increase could be higher than the average increase in variable costs.

In the analysis of the NOx SIP call, this pattern appeared to fit the case of the 0.15 alternative. Among coal-fired boilers, those units projected to retrofit with SNCR were not used to the maximum extent possible (in part because their costs of operation are high). By contrast, the coal-fired boilers retrofit with SCR, which have lower increases in marginal cost, were run almost continuously, and could not contribute to further increases in output. Thus, increases in electricity output tended to come from the under-utilized units retrofit with SNCR, and the marginal costs of electricity tended to reflect their high variable costs of control. Based on model results, it appears that marginal-cost-based prices would have risen by more than enough to cover *in aggregate* both the fixed and variable costs of the rule.

There is, however, no guarantee or even expectation that the increased revenues will accrue in exact proportion to increased costs. Rather, owners of units for which emissions are unusually low in the baseline (or for which costs of control are low) will tend to gain when prices rise as a result of the rule. Conversely, owners of high-emitting units that are costly to control will not necessarily recover all of their increased costs. The additional costs might then be borne by the owners of those units.

Because of the restructuring process that is accompanying the shift from regulated to free market conditions, the identities of the owners of the units is somewhat uncertain. The traditional, vertically integrated utility provides all of the functions of generation, transmission, distribution, and marketing services. Under competition, some of these functions are likely to be split off: utilities might sell off their generation capacity and/or turn over their marketing functions to other entities, possibly keeping their transmission and distribution functions. The owners of the power plants, who will presumably be responsible for reducing emissions and for holding sufficient allowances, might well be entities other than the utilities that currently own them.

Whether this change in ownership also means that any particularly high costs under the final Section 126 rule will fall on the new owners is less clear. To the extent that unrecoverable costs of compliance can be clearly predicted before the sale of the power plant, these potential costs will most likely be considered fully in the negotiations over the selling price. That is, unusually high-emitting plants will tend to have lower market values than clean ones. Only the costs that cannot be foreseen (resulting, perhaps, from unforeseen increases in allowance prices) will fall on the new owners. A significant portion of the costs of the rule might then be borne by the current owners of those generation assets that will cost the most to control. Because most utilities own a range of different types of generation capacity, with varying baseline NOx rates, some of the variability in costs can be expected to be canceled out: high costs for high-emitting generation will be balanced in many cases by plants with low or zero emissions.

Effects of Cost Increases during the Transition to Competition

As mentioned above, there may be cases in which electricity is sold at regulated retail prices for a period after the implementation of the final Section 126 rule. The effects of the regulations will ultimately depend on the decisions made by the utility regulators, and cannot therefore be predicted with assurance. Understanding the reason for the continued regulation of retail electricity prices might narrow the uncertainty over their possible effects.

One of the main reasons that some retail price regulation will persist is to deal with the problem of "stranded costs" — fixed costs that were incurred under a regulated environment for generation assets that would not be able to cover their full costs in a free market. Regulatory responses to the problem of stranded costs vary by Section 126 region and situation. In some cases, the issue of stranded cost recovery has been separated from the issue of free market rates by including on utility bills a separate, non-by-passable charge to cover stranded costs. The rest of the bill would be determined by the market, and could presumably take the effects of the final Section 126 rule into account.

In other cases, utility regulators have agreed to fix retail prices for the electricity sold by utilities that own these assets for a set period, rather than allowing the generating prices that customers will ultimately see to float down to free-market levels. If the utility is able to reduce its costs (of generation, or of purchasing power from other suppliers), while continuing to sell at a fixed rate, it will be able to cover some portion of its stranded costs. In some cases, the utilities agree to provide a discount from previous regulated rates, so that consumers can realize some of the advantages of the free market even during the transition. If the terms of the agreed-upon rate freeze (including the size of the initial discount) do not take into account the additional costs associated with the final Section 126 rule, the utility might be in the position of absorbing the costs of the rule for the length of the price freeze. State utility regulators may need to be cognizant of the potential effects of the final Section 126 rule on the need for stranded cost recovery.

6.4.2 Potential Electricity Price Changes

As discussed above, a reasonable basis for projecting price changes in response to cost increases is the increase in marginal costs of electricity production. Marginal cost changes (that is, cost changes that vary with firm or industry output) are key because they immediately affect the market equilibrium: if demand can be assumed to be relatively inelastic, microeconomic theory strongly suggests that almost all of a marginal cost increase will be quickly translated into increased prices. Because electricity demand has been relatively inelastic, in the short run, the change in marginal costs resulting from the rules is a reasonable upper-bound estimate of the change in electricity prices in the short run.

Annual marginal costs of electricity production could rise by about 0.6 mill/kWh in 2007, or about one percent of average revenues per kWh. Prices could rise by these same amounts as an upper bound estimate; to the extent that electricity demand is not completely inelastic, prices would not rise as much. If prices were to go up on the order of the changes in marginal costs, total revenues to the electric power industry, in the absence of a change in generation, would rise by about $1.2 billion in 2007, and the *net* revenues to the industry after the increase in costs would be on the order of a third of a billion dollars.[10] Estimating economic impacts is made somewhat more complex by the fact that generation is projected to be lower in some years under the final Section 126 rule than in the base case, by about one percent in 2007 for the 0.15 alternative, for example. This decline would require utilities within the Section 126 region to purchase more power from outside the Section 126 region (or import it from generating capacity they own outside the Section 126 region), though this increased cost would be largely balanced out by savings of the costs of generation.

6.4.3 Distribution of Cost Impacts Across Generation Types

Impacts on electricity producers will also depend heavily on the characteristics of their power plants. Utilities with an unusually high percentage of capacity and generation from units that start out with low emission rates, or are relative inexpensive to control, will generally have lower costs per kilowatt-hour of electricity produced. These utilities might include those that have already been regulated under other regulations, and therefore have low baseline emissions. Other utilities may have a preponderance of small coal-fired boilers with high baseline emissions rates. These utilities may have to install controls to reduce baseline emissions rates, and then may still have to purchase allowances in order to comply.

Though costs per kilowatt hour can be different for every affected unit, it can be instructive to show costs for typical units in the most important generator categories. Table 6-11 presents IPM results, from the NOx SIP call analysis, for four types of units: combustion turbines; gas combined cycle; oil/gas-fired boilers; and coal-fired boilers. Within each type, results are shown for small and large examples, where sizes are selected as the lower and upper quartiles of the size distribution, respectively. The population is further subdivided into examples with low initial NOx rates (at the lower quartile of rates) and high initial NOx rates (at the upper quartile). Finally, for the boilers, examples for cases with SCR and SNCR are displayed. These estimates were prepared for the NOx SIP call RIA. Equivalent estimates for the final Section 126 rule can be expected to be very similar given the similarity between final Section 126 and NOx SIP call sources and the similarity between fuel mix and utilization.

Costs, displayed in mills per kilowatt hours, are calculated by adding the cost of the control technology (if any) to the number of allowances that could be sold, times an estimate of the value of the allowances. For the purposes of exposition, allowance prices are assumed to be $3,000 per ton, on the basis of the marginal cost of NOx reductions in the 0.15 alternative over the analytical period. The number of allowances that could be sold is calculated by comparing controlled emission rates to an estimate of the allowances that would be allocated to the unit under the 0.15 alternative, and multiplying by an estimate of the fuel input to the unit over the ozone season. The total net cost of compliance, considering both control measure costs and

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[10] The price increase of 0.6 mill/kWh is smaller than the average cost increase of 0.92 mill/kWh of affected generation. There are two reasons that the revenue increase would, nonetheless, exceed the cost increase. First, not all of the generation in the final Section 126 region is affected by the rules. Second, the price increase would apply to a wider area than the cost increase; total generation in the 13 affected jurisdictions accounts for only about 60 percent of total generation in the electricity market regions where prices would be affected.

allowance costs or revenues, is then divided by estimated annual generation to yield an average cost per kWh.

As seen in the table, typical combustion turbines and combined-cycle plants realize savings rather than costs from the rule (not counting administrative or monitoring costs). Because their emission rates are typically low even in the baseline (due in some cases to previously installed control devices), they are not assumed to be retrofitted with additional emission control devices.

Oil- and gas-fired boilers with low initial rates can experience savings analogous to those for combustion turbines and combined cycle units. Oil and gas boilers with high rates can have net costs, with or without the addition of control technology. If electricity prices rise appreciably (in step with changes in marginal costs, for example) as a result of the final Section 126 rule, some owners of oil and gas-fired boilers would be better off because their control costs would be lower than the industry-wide increase in marginal costs.

Coal-fired boilers, which provide the majority of fossil generation, can have costs in the range of one mill per kilowatt hour. This cost is comparable to the average costs under the final Section 126 rule for all generation under the 0.15 alternative. That cost increase, of 0.98 mills/kWh, is shown in Table 6-9. As shown in Table 6-11, costs can be expected to be higher for smaller units (1.0 - 1.6 mills/kWh) than for large units (0.4 - 1.0 mills/kWh). Costs will also tend to be higher for those units with higher baseline rates (including some Group 2 boilers, which were not required to reach low rates under Title IV). The range of costs presented in Table 6-11 were prepared for the NOx SIP call and were not recalculated for the final Section 126 rule. The average cost increase for all generation under the NOx SIP call was calculated to be 0.68 mills/kWh. The ranges below might vary slightly the cost increases for small and large units under the final section 126 rule, given that the sources in the Section 126 region and the NOx SIP call region are similar, but not exactly the same.

Analysis of the IPM results also shows changes in capacity factors for some of the typical units in response to the final Section 126 rule. These changes were calculated for the SIP call analysis, and are likely to be similar for the final Section 126 rule. Units that employ SNCR are most likely to reduce their capacity factors, and those with low controlled rates (either coal with SCR or gas turbine/CC) are likely to increase their capacity factors. As discussed above, this pattern leaves the marginal units more likely to have high marginal costs of generation, because the units with available capacity face additional costs of purchasing reagent and allowances when they increase generation. The units that reduce their capacity factors will lose the revenues that would have accompanied their lost output; on the other hand, they also save their variable costs of operation for those kilowatt hours.

Table 6-11
Potential Net Cost (After Allowance Purchases/Sales) by Unit Type

For the NOx SIP Call 0.15 Trading Alternative in 2007
(mills/kWh, 1990$)

	Small Units		Large Units			
Unit Type	**Low Initial NOx Rate**	**High Initial NOx Rate**	**Low Initial NOx Rate**		**High Initial NOx Rate**	
Combustion Turbine	(Unaffected)	(Unaffected)	-1.3		-0.4	
Gas Combined Cycle	-1.3	-0.3	-2.0		-0.3	
Oil/Gas Fired Boiler	0.0	0.8	-0.5	-0.4 (SNCR)	0.5	0.1 (SNCR)
Coal Fired Boiler	1.0 (SNCR)	1.6 (SNCR)	0.9 (SCR)	0.4 (SNCR)	1.0 (SCR)	0.5 (SNCR)

Source: ICF analysis.

6.4.4 Potential Impacts on Small Electricity Generators

To investigate the possibility that small utilities and other small affected entities could be adversely affected by the final Section 126 rule, EPA has conducted a screening analysis of small entity impacts. That analysis reveals that a relatively small number of small utilities are potentially affected in this analysis, in part because coverage is limited to units greater than 25 MW, and in part because small utilities are more common in the western states that are outside the 13 jurisdictions named in the final Section 126 rule. Of almost 900 utilities nationwide that generate electricity, over 700 are considered small by SBA's definition (of less than 4 billion kWh per year). Only 95 of these small utilities are found in the Section 126 region, however, and of these 53 own fossil-fuel fired units. Excluding those utilities that have no units greater than 25 MW and utilities that fail to meet other selection criteria relating in particular to the availability of data on size, generation type, and emissions, leaves 19 small potentially affected utilities.

Though many of these small utilities will be affected to a minor degree only, about half may experience cost increases that are greater that one percent of their electricity-based revenues under EPA's illustrative implementation scenario. The small utilities that may be more seriously affected tend to be those relying more heavily on coal-fired boilers, especially cyclones (which tend to have high uncontrolled emissions and are not subject to tight controls under Title IV), and those with units whose baseline NOx emission rates are unusually high. While these utilities constitute almost half of *affected* small utilities, they are about nine percent of the small utilities that may be affected in the absence of the size cut-off established by EPA to limit impacts on small sources.

In a search for small non-utility generators in the Section 126 region, EPA identified approximately 109 affected units that generate electricity but are not owned by a utility. The owners of almost all of these units are identified using a data base of non-utility generators. Data collected on the revenues, SIC codes, and total generation of the owners or their parent companies are used to divide the owners into small and large entities. Entities for whom revenue data are unavailable are assumed to be small in order to estimate a conservative "worst case" scenario. In all, 61 small non-utility entities with units greater than 25 MW are analyzed.

Estimated costs of compliance are calculated under the conservative assumption that all small non-utility units comply through the purchase of allowances. This approach would tend to overstate compliance costs because it does not consider cases in which emission reductions can be achieved at costs below the marginal cost of reductions in the final Section 126 region. In the 0.15 trading alternative, five entities judged to be small are projected to face costs in excess of one percent of revenues under EPA's illustrative implementation scenario. These 5 entities constitute about 8 percent of the 61 small non-utilities analyzed.

Adding 9 small utilities to 5 small non-utility entities yields a total of 14 small entities in the trading program with projected costs in excess of one percent of revenues. These 14 entities constitute about 18 percent of all small affected entities (14 of 80). This percentage would be smaller if the number of affected entities was compared to all affected and potentially affected entities (i.e., owners of all units, regardless of size).

6.4.5 Potential for Closures and Additions of Capacity

A potentially important measure of the economic impacts of a rule is the number of potential closures predicted to result from the rule. Closures occur when the costs of compliance are so high as to make the net present value of future operation negative, leading to the abandonment of a productive asset as the least-costly alternative. New installations of capacity induced by the rule constitute another important measure.

The results of the IPM analysis show that some capacity could be shut down or retired early as a result of the final Section 126 rule. At most, 113 MW of coal-fired capacity and 326 MW of oil/gas-fired capacity, out of a total of over 150,000 MW, are projected to close. Thus, all but 0.3 percent of capacity would continue to operate under the final Section 126 rule. These potential closures will be more than offset (in terms of capacity) by an increase in combined-cycle units of between 803 and 3,517 MW (depending on the alternative).

6.5 Indirect Economic Impacts

In addition to impacts on the entities that are potentially directly affected by the rules, there will be some impacts on sectors of the economy that interact with the electricity generating industry. This section briefly examines the potential effects on fuel suppliers, industrial users of electricity, and households.

6.5.1 Potential Employment Impacts

Emission control devices will have to be installed as a result of the final Section 126 rule. Thus, the rule will generate an initial demand for workers to install emission control technology and a continuous demand for workers to operate and maintain the technology. Tables 6-12 and 6-13 present the potential impact on employment in the control technology sector for the 0.15 alternative.

Table 6-12
Potential Impact on Employment in the Control Technology Sector for the 0.15 Trading Alternative (Construction and Installation)

Labor Required for Construction and Installation 2000 - 2003				Increased Annual Labor Demand, assuming construction and installation take three years (FTEs)
Combustion Controls (worker-years)	**SCR (worker-years)**	**SNCR (worker-years)**	**Total (worker-years)**	
3,371	17,741	7,260	28,372	9,457

Source: ICF analysis.

Table 6-13
Potential Impact of 0.15 Trading Alternative on Operations and Maintenance (O&M) Labor Requirements in the Control Technology Sector in 2007
(Full-Time Equivalent)

SCR	SNCR	Total
261	339	600

Source: ICF analysis.
No additional O&M assumed to be required for combustion controls.

The final Section 126 rule may also affect demand for labor in the coal and natural gas sectors. Coal produced is likely to decrease while natural gas production is likely to increase. Projections for the change in coal and natural gas demand were developed for the NOx SIP call, as shown in Tables 6-14 and 6-15. This analysis has not been updated; because of the smaller overall scale of the final Section 126 rule, the projections shown in the tables probably overstate the employment effects of final Section 126 rule on coal and natural gas workers. Further, EPA did not estimate the potential additional indirect impact on labor demand for coal transportation workers, but it is expected to be smaller the than potential changes in production workers.

Table 6-14
Potential Effects of 0.15 Trading Alternative on Coal Production and Employment Demand in 2007

	Total Nationwide Coal Production, Initial Base Case (million tons)	Change in Coal Production in Response to NOx SIP Call, 0.15 Alternative (million tons)	Labor Hours (thousands)	Change in Labor Requirement (FTE)
Eastern U.S.	511.7	-4.6	-809	-392
Western U.S.	513.7	-2.6	-113	-44

Source: ICF analysis. Assumes growth in output per worker to 11,734 tons/yr for eastern miners, 58,433 tons/yr for western miners. See base case assumptions and EPA, June 1997.

Table 6-15
Potential Effects of 0.15 Trading Alternative on Natural Gas Production and Employment Demand in 2007

Initial Base Natural Gas Use (billions of cubic feet)	Increase in Natural Gas Use (billions of cubic feet)	Labor Demand (FTE per billion cubic feet per year)	Change in Labor Requirement (FTE)
1,928	80	7.48	600

Source: ICF analysis.

Table 6-16 presents the potential overall impact on labor demand in 2007. The increase in demand for control technology construction and installation workers is not taken into account in calculating the net change in labor demand because these workers are needed only during the construction and installation stage (the first three years). As shown, the labor demand in 2007 is likely to increase by 764 workers as a result of the final Section 126 rule.

Table 6-16
Summary of Potential Labor Demand Impacts of 0.15 Trading Alternative in 2007

Market Segment	Change in Labor Requirement (FTE)
Coal Production - East	-392
Coal Production - West	-44
Natural Gas Production	600
Emission Control Technology (O&M) [a]	600
Net Change	**764**

Source: ICF analysis.
[a] There will also be a labor requirement equivalent to 9,457 FTEs per year for pollution control system installation between 2001 and 2003.

6.5.2 Potential Impacts on Industrial Users of Electricity

The potential costs of the final Section 126 rule are expected to be passed along to electricity users through rate increases, as discussed in Section 6.4. Whether the rate increases significantly affect industrial users depends both on the size of the increases and the amount of electricity used, relative to industrial output. Total net electricity use by manufacturing sectors in 1994 was 2,656 trillion Btu, which equals 778 billion kWh. The value of total shipments from the manufacturing sector in 1995 was $3,119 billion (in 1990 dollars), of which $1,485 billion represented value added (as opposed to the value of purchased materials and other inputs). Thus, on average, the manufacturing sector used 0.25 kWh of electricity per dollar of output (or 0.52 kWh per dollar of value added). If the price of electricity rises by 0.6 mill/kWh in 2007, which is the approximate generation-weighted increase in marginal costs, industry would experience a cost increase of 0.25 * $0.6/1000 or a 0.015 cents for each dollar of shipments, or 0.03 cents for each dollar of value added. The cost increases, then, would be a few hundredths of a percent of the value of output on average.[11]

These calculations refer only to the average manufacturing entity. Some industries use considerably more electricity than others, meaning that the potential impacts could be more serious for some entities. Table 6-17 shows the electricity use, value added, and value of shipments for the six two-digit manufacturing industries that use the most electricity per dollar of value added. Table 6-15 also shows the effect of a 0.6 mill increase in the electricity prices per kWh as a percentage of the two output measures. As seen, even the costs for the most electricity-intensive two-digit industries is below a quarter of one percent.

Table 6-17
Potential Impacts of Electricity Rate Increases in 2007 on Energy-Intensive Industries of 0.15 Trading Alternative
(by Two-Digit SIC Code, 1990$)

Industry	SIC Code	Net Electricity Use (billion kWh)	Total Output of Industry (billion 90$)		Electricity Used per Dollar of Output (kWh/90$)		Potential Increase of 0.6 mill/kWh[a] as a Percentage of Output	
			Value Added	Value of Shipments	Value Added	Value of Shipments	Value Added	Value of Shipments
Primary Metals	33	144	$61	$156	2.37	0.92	0.14%	0.06%
Petroleum and Coal Products	29	35	$28	$131	1.26	0.27	0.08%	0.02%
Textile Mill Products	22	33	$29	$70	1.15	0.47	0.07%	0.03%
Stone, Clay, and Glass Products	32	36	$37	$66	0.99	0.55	0.06%	0.03%
Paper and Allied Products	26	65	$70	$150	0.93	0.43	0.06%	0.03%
Chemicals and Allied Products	28	152	$171	$315	0.89	0.48	0.05%	0.03%
All Other Manufacturing		311	$1,091	$2,231	0.28	0.14	0.02%	0.01%

Source: *1997 Statistical Abstract*, table 930 and 1219, pp. 587, 739-743, and ICF calculations. One kWh assumed to be 3,412 Btu.
[a] Potential increase under full competition in the electric power industry with marginal cost pricing. Actual increase may be less if full competition does not occur.

Table 6-18 shows the electricity demand, value of shipments and the effect of an increase in electricity prices per kWh as a percentage of value of shipments for the four-digit manufacturing industries that use the most electricity per dollar of output. A total of nine industries at the four-digit level had costs greater than the industry with the highest costs at the

[11] *1997 Statistical Abstract of the United States*, U.S. Department of Commerce, Bureau of the Census, Tables 1219 and 930, pp. 739 and 587.

two-digit level. Even for these few electricity-intensive industries, cost impacts would be less than one percent.

Table 6-18
Potential Impacts of Electricity Rate Increases in 2007 on Energy-Intensive Industries of 0.15 Trading Alternative
(by Four-Digit SIC Code, 1990$)

Name	SIC Code	Electricity Demand (million kWh)	Value of Shipments (million 1990$)	Electricity Demand per Dollar of Output (kWh/90$)	Potential Increase of 0.6 mill/kWh[a] as a Percentage of Value of Shipments
Industrial Gases	2813	22,816	$3,051	7.48	0.45%
Electrometallurgical Products, Except Steel	3313	4,797	$1,020	4.70	0.28%
Industrial Inorganic Chemicals, NEC	2819	42,786	$14,530	2.94	0.18%
Cement, Hydraulic	3241	10,789	$5,125	2.11	0.13%
Primary Smelting and Refining of Nonferrous Metals	3339	4,205	$2,509	1.68	0.10%
Lime	3274	1,151	$805	1.43	0.09%
Paper Mills	2621	37,503	$33,485	1.12	0.07%
Glass Containers	3221	4,268	$3,825	1.12	0.07%
Steel Works, Blast Furnaces (Including Coke)	3312	45,463	$45,587	1.00	0.06%

Source: EIA, *1996 Electric Sales and Revenue*, Dec. 1997; Bureau of Economic Analyses, Shipments of Manufacturing Industries, www.bea.doc.gov
[a] Potential increase under full competition in the electric power industry with marginal cost pricing. Actual increase may be less if full competition does not occur.

6.5.3 Potential Impacts on Households

Impacts on household budgets will be smaller than the percentage increase in electricity prices, because electricity is only one component of expenditures. Households used 961 billion kWh of electricity in 1993, or an average of almost 10,000 kWh per household.[12] An increase of 0.6 mill/kWh would add about $6 annually to the average household budget. As median income per household was over $29,500 in 1995 (in 1990 dollars), the typical increase in electricity cost would take an additional 0.02 percent from the income of a typical household.[13]

The impacts would be higher for households with unusually high electricity demand or unusually low incomes. Table 6-19 shows typical annual electricity bills for households in

[12] *1997 Statistical Abstract*, Table 929, p. 587.

[13] *1997 Statistical Abstract*, Table 719, p. 466.

different parts of the income distribution, and the effect that an increase in electricity prices of 0.6 mill/kWh would have on their incomes.

Table 6-19
Potential Impacts of Electricity Rate Increases in 2007 on Households by Income Category of 0.15 Alternative
(1990$)

Income Category	Assumed Annual Income	Typical Annual Electricity Bill	Electricity as a Percentage of Income	Potential Increase of 0.6 mill/kWh[a] as a Percentage of Income
Less than $15,000	$7,500	$544	7.3%	0.07%
$15,000 to $34,999	$25,000	$704	2.8%	0.03%
$35,000 to $74,999	$55,000	$832	1.5%	0.01%

Source: *1997 Statistical Abstract*, Table 720, p. 467, and ICF calculations, assuming an average price of electricity of 6 cents per kWh.
[a] Potential increase under full competition in the electric power industry with marginal cost pricing. Actual increase may be less if full competition does not occur.

Table 6-19 shows that electricity use rises with income, but not in direct proportion: households with very low incomes spend almost as much as those with substantially higher incomes. Thus, electricity takes a larger percentage of income from the poor than from the rich. Because of the size of the increase in electricity prices expected to result from the final Section 126 rule is small, the effects on even the least-well-off households will be much smaller than one percent. Most households are likely to see a net reduction in electricity rates over the coming decade as a result of the savings from restructuring, despite the increases from the final Section 126 rule.

Variations in impacts on residential consumers in different parts of the final Section 126 region are also estimated. Because per-household electricity use varies from State to State, costs impacts by State vary as well. The 1996 median electricity expenditures as a percentage of household income was 2.08 percent across the entire Section 126 region. Residents of New Jersey and New York spend less than 1.5 percent of their incomes on electricity; consumers in these States are likely to have relatively smaller cost increases. On the other hand, the ratio of electricity expenditures to income was 3.1 percent in Kentucky and 3.3 percent in West Virginia. The final Section 126 rule could have somewhat larger effects on consumers in these States, because any given increase in electricity prices will be applied to larger portions of their incomes. Even in these States, though, the price increases likely to result from the final Section 126 rule will be less than a tenth of one percent of income.[14]

[14] *1997 Statistical Abstract*, Table 722, p. 468. *EIA Electric Sales and Revenue*, 1996, Tables 5 and 6, p. 17-18.

6.6 Administrative Costs

Administrative Costs for Electricity Generating Units

Administrative costs to operators of electricity generating units are associated with monitoring and reporting NOx emissions, reporting additional compliance information, permitting and allowance trading.

All permitting activities will take place prior to 2003 and will be spread out over the years 2000 through 2002, therefore EPA anticipates no costs associated with permitting in 2007. EPA anticipates that the average cost of permitting will be $734 per unit, with total costs of $212,037 in 2000, $251,650 in 2001 and $251,650 in 2002. This assumes that all coal-fired units will need permits to construct because they will be installing control equipment and that 1/3 of the units will get permits to construct in 2000, 2001 and 2002. It also assumes that 1/5 of all of the units will need to make revisions to their title V permits in 2001 and 2002.

In 2007 EPA anticipates a total cost of $8,385,695 associated with monitoring and reporting NOx emissions and reporting additional compliance information. This is an average unit level cost of $8600.71. The actual unit level cost will vary depending upon the current monitoring requirements that the unit is meeting. For instance a unit that is currently subject to both the Acid Rain Program and the OTC NOx Budget Trading Program will have very minimal costs associated with this program since they are already meeting requirements to monitor NOx mass, hold allowances and submit end of season compliance certification. An industrial source that is not currently subject to either the Acid Rain Program or the OTC program will have the most significant costs because all of the requirements of this program will be new.

The number of units determines the cost of monitoring, permitting, and reporting. All 1,130 units in the final Section 126 region will incur compliance reporting and permitting costs.[15] A Title V operating permit is required for each unit every five years. The unit permitting costs in Table 6-20 may appear to be low because they have been annualized over the five year permit cycle. EPA assumes that 720 units have incremental compliance requirements.[16] EPA assumes that administrative costs will not vary among the regulatory alternatives considered because the number of units does not vary much by alternative.

Table 6-20 presents the estimated transaction costs to owners of electricity generating units for trading allowances under the different regulatory alternatives. Transaction costs are estimated to be 1.5 percent of the total values of the traded allowances.

[15] EPA assumed that the total number of units in the final Section 126 region was simply 57 percent of the 1,982 units in the NOx SIP call region, where 57 percent is the ratio of the number of jurisdictions in the section 126 region (13) divided by the number of jurisdictions in the NOx SIP call region (23).

[16] This estimate of 720 units was calculated as 57 percent of the 1,263 units that were identified as having incremental compliance costs for the Federal Implementation Plan (FIP) ICR, where 57 percent is the ratio of the number of jurisdictions in the final Section 126 region (13) divided by the number of jurisdictions in the NOx SIP call region (23). These units were assumed to have emissions monitoring costs in addition to reporting and permitting costs.

Table 6-20
Allowance Trading Transaction Costs for
Electricity Generating Units by Alternative in 2007

Alternatives (lbs/mmBtu)	Transaction Costs[a] (million 1990$)
0.25 Trading	$0.3
0.20 Trading	$0.5
0.15 Trading	$0.9
0.12 Trading	$2.3

[a] Total cost of allowance is included in compliance costs; only transaction costs of trading are presented here.
Source: ICF analysis.

Total Administrative Costs

Table 6-21 presents the estimated total annualized administrative costs to owners of electricity generating units by alternative. The costs presented are incremental to the Initial Base Case. The total administrative costs include monitoring, compliance reporting, permitting, and allowance trading transactions costs.

Table 6-21
Total Administrative Costs to Owners of
Electricity Generating Units in 2007

Alternatives (lbs/mmBtu)	Total Annualized Administrative Costs (million 1990$)
0.25 Trading	$3.7
0.20 Trading	$3.9
0.15 Trading	$4.3
0.12 Trading	$5.6

Source: ICF analysis.

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Chapter 7. Results Of Cost, Emissions Reductions , And Economic Impact Analyses For Non-Electricity Generating Units

This chapter presents the results of the cost and economic impact analyses for industrial boilers, combustion turbines and process heaters. The cost and economic impact analyses (including potential impacts to small entities and public sector entities) evaluate the potential impacts associated with the final Section 126 rule. The results depend on assumptions about how the States will implement the requirements associated with control of NOx emissions from the source categories named in the petitions filed with EPA. In an effort to narrow the scope of sources affected by this rule, only large sources are potentially affected as decreed by EPA. This is consistent with recommendations provided by the petitioning States (see Chapter 2). A summary of the results presented in this chapter is found in Section 7.1. The results of the average cost-effectiveness analysis for each of these source category groups are found in Section 7.2. Section 7.3 describes the potential economic impacts of the final alternative and other alternatives, and Section 7.4 analyzes the potential impacts on small entities in particular. The economic impact sections focus on detailed results for the final alternative and provides a brief comparison with the range of results for other options considered. More detailed results for the other options considered are provided in the economic impact analysis report (Abt, 1999). Section 7.5 provides a list of analytical limitations and uncertainties that should be understood when reviewing the results in this chapter. Finally, references for the chapter are provided in Section 7.6.

This chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). This final notice presented the final Section 126 remedy (0.15 trading - utilities; 60% control - industrial boilers and combustion turbines). It should be noted that the results primarily reflect application of the final Section 126 remedy to all sources in a named source category in each State in the final Section 126 region. The results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS. Costs are expressed in 1990 dollars, but are summarized in 1997 dollars in Section 7.1 for ease of comparison with the costs of the proposed and final Tier 2 rules and prospective Section 812 study.

7.1 Results in Brief

The total annual compliance costs in 2007 for regulatory alternatives applied to non-EGU sources in the final Section 126 region range from $44.6 million to $179.6 million in 1997 dollars ($36.2 million to $145.9 million in 1990 dollars). The total annual compliance costs in 2007 for the final alternative (60% control) is $94.2 million in 1997 dollars ($76.5 million in 1990 dollars). The estimated NOx emissions reductions for the same alternatives in the final Section 126 region in 2007 range from 27,200 to 60,400 tons, and the NOx emissions reductions for the final alternative estimated at 48,300 tons. The average cost-effectiveness for these alternatives ranges from $1,636/ton to $2,977/ton in 1997 dollars ($1,329/ton to $2,418/ton in 1990 dollars), and the average cost-effectiveness in 2007 for the final alternative is $1,956/ton in 1997 dollars ($1,589/ton in 1990 dollars).

7.2 Compliance Costs and Cost-Effectiveness

Various regulatory alternatives are analyzed for the sources affected by the final Section 126 rule. Impacts are estimated as well as emissions reductions for the large (as defined in Chapter 3) industrial boilers and combustion turbines at regulatory alternatives based on 40%, 50%, 60%, and 70% reduction of NOx, respectively, from projected 2007 uncontrolled emissions. These alternatives apply the specified control level across the entire final Section 126 region. Impacts are estimated for process heaters for five regulatory alternatives based on average cost-effectiveness ceilings per source (expressed in 1990 dollars) of: $1,500, $2,000, $3,000, $4,000, and $5,000.[1] The potential costs of complying with the final Section 126 rule have two elements: implementation (the cost of emissions control) and administration (the cost of monitoring emissions, and the associated administrative costs of recordkeeping and reporting.)[2] The calculation of administration costs is presented later in Section 7.1.4.

For each source category named in the 8 final Section 126 petitions, EPA's estimates of emissions reductions and compliance costs reflect the Agency's framework for highly cost-effective NOx emissions reductions. These proposed control measures are selected through a 2-step process. First, EPA examined the control measures's technical feasibility, administrative feasibility, and average cost-effectiveness for NOx control applied in the ozone season across the entire final Section 126 region. Second, EPA determined those measures that feasibly achieve the greatest NOx reductions and are among the most reasonable in light of other actions undertaken or proposed by EPA and States to control NOx. Based on this process, the Agency considers controls with an average cost-effectiveness, evaluated across all sources in a category group, of less than $2,000 (1990 dollars) per ozone season ton of NOx removed to be highly cost-effective. EPA has calculated the amounts of emissions based on application of these controls.

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[1] The analysis of affected industrial boilers and combustion turbines is based on emissions trading occurring across the entire final Section 126 region. The analysis of affected process heaters considers control measures or technologies applied at the source-level up to a specified cost per ton cutoff. For more details, refer to Chapter 5.

[3] One category of costs -- the transaction costs associated with trading allowances -- is not included in the cost estimates discussed in these chapters. These costs will depend on the number of sources that elect to engage in trading. Analysis of EGUs with the IPM indicates these costs are 1.5% of compliance costs, so they are expected to be small.

7.2.1 Results for Industrial Boilers and Combustion Turbines

In EPA's analysis, large industrial boilers and combustion turbines are included in the NOx Budget Trading Program. Currently, the IPM model, discussed in Chapter 4, does not cover these sources, so EPA has conducted a separate least-cost analysis for this group of sources. The least-cost analysis is EPA's attempt to simulate the outcome of an efficient emissions trading program by assigning control responsibility based on sources with the lowest control costs. The least cost analysis only reflects the efficient allocation of control responsibility among the group of industrial boilers and turbines, and does not, therefore, take advantage of potentially more efficient outcomes that could occur if these sources were modeled in conjunction with the rest of the utility sources included in the NOx Budget Trading Program.

Table 7-1 shows the emissions reductions achieved in the least-cost analysis for each regulatory alternative. The table indicates that the alternatives achieve incremental reductions from the 2007 Clean Air Act (CAA) baseline ranging from 30 % to 67 %.

Table 7-1
2007 Ozone Season NOx Baseline Emissions and Emission Reductions for Large Industrial Boilers and Combustion Turbines[a]

Regulatory Alternative[b]	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
40% Control	235	90,469	63,230	27,239
50% Control	272	90,469	52,742	37,727
60% Control	308	90,469	42,149	48,320
70% Control	319	90,469	30,117	60,352

[a] The 2007 baseline emissions estimate reflects emissions from all 321 large sources (312 industrial boilers, 9 combustion turbines) in this source category, both controlled and uncontrolled.

[b] Reductions from the controlled 2007 baseline are less than the nominal percentage reduction from an uncontrolled 2007 baseline indicated in the regulatory alternative name.

Table 7-2 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative. The annual control costs range from $28.6 to $135.6 million (1990 dollars). Annual monitoring and administrative costs depend on the number of covered sources, and these costs range from $7.6 to $10.3 million (1990 dollars). The accompanying average cost-effectiveness results range from $1,329 to $2,418 per ozone season ton (1990 dollars). The 60% control level is the most stringent control level that meets EPA's framework for highly cost-effective ozone season NOx emissions reductions, and is selected as the basis for establishing State level emissions budgets for the final Section 126 rule.

Table 7-2
2007 Cost and Cost-Effectiveness Results for Large Industrial Boilers and Combustion Turbines

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
40% Control	$28.6	$7.6	$36.2	$1,329
50% Control	41.9	8.8	50.7	1,370
60% Control	66.5	10.0	76.5	1,589
70% Control	135.6	10.3	145.9	2,418

7.2.2 Results for Process Heaters

The analysis of large process heaters, as prepared in the proposed section 126 rule and reproduced here, is conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative.

Table 7-3 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative. Annual monitoring and administrative costs are not estimated for this category of sources because it is evident from Table 7-3 that even without these additional costs there is no regulatory alternative that meets EPA's criteria for highly cost-effective ozone season NOx emissions reductions. That is, when emissions decreases are considered at all large process heating sources (i.e., regulatory alternatives applying greater than $3,000/ton (1990 dollars) of control), the resulting average cost-effectiveness clearly exceeds EPA's $2,000/ton (1990 dollars) framework. Since the costs of control per ton emission reduction for this source category exceeds EPA's cost effectiveness framework, it is not included in the NOx emissions decreases for the Statewide budgets under the final Section 126 rule.

Table 7-3

2007 Cost and Cost-Effectiveness Results for Large Process Heaters

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs[a] (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
$1,500/ton	na	na	na	na
$2,000/ton	na	na	na	na
$3,000/ton	31.6	na	$31.6	$2,860
$4,000/ton	32.8	na	32.8	2,896
$5,000/ton	32.8	na	32.8	2,896

na = not estimated because no control measures were identified that meet the regulatory alternatives's cost-effectiveness ceiling.

7.2.3 Summary of Results for Non-Electricity Generating Sources

Table 7-4 contains emission reductions and costs associated with the final regulatory decisions arising from the cost-effectiveness analysis. The final combination of regulatory alternatives achieves an ozone season NOx emission reduction of approximately 48,000 tons beyond the 2007 baseline. This represents approximately a 53% reduction from the baseline for these combined sources.

Table 7-4
2007 Ozone Season Emission Reductions and Total Annual Compliance Costs for Non-Electricity Generating Sources Used to Establish State NOx Emissions Budgets under the final Section 126 Rule [a]

Source Category	Baseline Ozone Season Emissions	Ozone Season Emissions After Control	Total Reduction in Ozone Season Emissions	Total Annual Compliance Costs (million 1990$)
Industrial Boilers	89,641	42,003	47,638	75.7
Combustion Turbines	828	147	681	0.8
TOTAL	90,469	42,150	48,319	76.5

[a] Emissions estimates are for large sources only. The emissions reduction estimates reflect the final alternative for the affected non-EGU sources (60% control of large industrial boilers and combustion turbines).

Table 7-5 indicates the control technologies represented by the final regulatory decisions arising from the cost-effectiveness analysis. The table shows that combustion modifications, such as oxygen trim and water injection (OT + WI), are the dominant control technologies for boilers and turbines.   Overall, selective catalytic reduction (SCR) is estimated to be applied to 11% of large non-EGU sources in EPA's analysis. Selective non-catalytic reduction (SNCR) is applied to 16% of large units, and OT+WI is applied to 55% of large units.

Table 7-5
Control Technologies Selected for Non-Electricity Generating Sources for Regulatory Alternatives Used to Establish State NOx Emissions Budgets under the Final Section 126 Rule [a]

Control Technology	60% Control for Industrial Boilers and Combustion Turbines
SCR	35
SNCR	50
OT + WI	175
OTHER[b]	61
TOTAL	321

[a] These results represent the number of emissions units for which the specified control technology is applied in the control cost analysis.
[b] Includes sources that are estimated NOT to apply additional controls.

7.2.4 Adminstrative Costs for Non-Electricity Generating Units

The burden to other stationary source operators potentially resulting from implementation of the final Section 126 rule are primarily associated with costs of installing and operating a continuous emissions monitoring system (CEMS) to monitor NOx mass emissions and demonstrate compliance with limits established by a State. This burden includes the total time, effort, and financial resources expended by an operator to generate, maintain, retain, or disclose information to or for a Federal or State agency.

A large proportion of the affected non-EGU sources are expected to install CEMS and/or upgrade their data acquisition and handling systems (DAHS) in order to participate in the NOx trading program. For sources subject to Title IV monitoring in the Ozone Transport Region (OTR), only administrative costs of recordkeeping and reporting were estimated. These units will not potentially experience additional capital costs or operating and maintenance costs as a result of this rulemaking since they are already equipped with a CEMS meeting Part 75 Subpart H specifications. However, Title IV units that are not in the OTR will likely require minor upgrades to their DAHS. Therefore, the burden estimate associated with this rulemaking for these sources includes additional capital costs and operating and maintenance costs.

For units not subject to Title IV monitoring but in the OTR, costs are estimated for upgrading the DAHS and performing annual quality assurance testing. For trading units not subject to the Title IV monitoring and not in the OTR, additional costs may result from installing a NOx CEMS, or other approved monitoring system, and a DAHS. The Part 75 NOx monitoring requirements vary depending on the fuel burned and the hours of operation. For example, monitoring requirements are less stringent for gas/oil fired sources than for coal-fired sources, and are even less stringent for peaking units and low NOx mass emissions sources.

Table 7-6 presents estimates of the per-source annual administrative costs that other stationary source operators may experience, based on assumptions of how States will implement administrative requirements in response to this rulemaking. These estimates are prepared for both trading and non-trading sources and included in the cost analysis results.

Table 7-6
Average Annual Administrative Costs Per Source for
Non-EGU Sources in 2007
(1990 dollars)

Source Category Group	Annual Monitoring Costs	Annual Reporting & Permitting Costs	Total Annual Administrative Costs
Industrial Boilers and Combustion Turbines	$27,000	$5,000	$32,000

7.3 Potential Economic Impacts

This section presents the results of a screening-level economic impact analysis for industrial boilers and turbines and other stationary sources potentially affected by the rule. The analysis estimates the potential impact on facilities and firms affected by the rule by comparing compliance costs to estimated sales or expenditures. Facilities and firms for whom costs exceed three percent of sales or expenditures are identified as the most possible to experience significant impacts as a result of the rule. Those for whom costs exceed one percent of sales or expenditures are also highlighted as potentially experiencing significant impacts. Costs that represent less than one percent of sales or expenditures are not expected to experience significant impacts.

The Agency elected to evaluate the potential impacts of the rule on potentially affected small entities. The analysis of small entity impacts is an update of the Final Regulatory Flexibility Analysis (FRFA) completed for the May 25 NFR . The analysis accounts for updates in the NOx emissions inventory and the reduced geographic scope of the final Section 126 rule as a results of the Agency's stay of the findings based on the 8-hour ozone NAAQS.

The analysis of impacts is conducted at three levels: establishment (or facility or plant), firm and industry:

- Costs at the source level are aggregated for each establishment, where an establishment owns more than one affected source. Establishment-level costs are then compared with estimated sales or expenditures for the average sized establishment in the relevant industry (4-digit SIC) and employee size category (small vs. large), as described in Chapter 5.

- Establishment-level impacts are summarized at the industry level, as defined by 4-digit SIC codes.

- Finally, costs are further aggregated to the firm level to account for the fact that some firms own more than one establishment affected by the rule. Firm-level costs are compared with firm sales, obtained for the most part from Dun & Bradstreet data, as described in Chapter 5. For governments, costs are compared with revenues, and for colleges and universities, costs are compared with expenditures.

Individual potentially affected establishments and firms may have both industrial boilers and combustion turbines affected by the rule.

Section 7.3.1 provides an overview of the potentially affected firms, facilities and sources. Detailed economic impacts are presented in Section 7.3.2 for the final regulatory alternative -- a 60% reduction from uncontrolled 2007 emissions for industrial boilers and combustion turbines.

Throughout the discussion, economic impacts are presented separately by size of the potentially affected entity that owns the affected establishments. Section 7.3.2 discusses firm-level impacts for potentially affected small entities in more detail. Chapter 8 discusses impacts on potentially affected government-owned entities in more detail.

7.3.1 Overview of Potentially Affected Sources, Establishments and Firms

Table 7-7 shows the number of firms potentially affected under the final alternative, by source category.[3] Table 7-8 shows the same information by sector and by size of entity.

Table 7-7
Number of Firms and Other Entities Potentially Affected, by Source Category

[3] One category of costs -- the transaction costs associated with trading allowances -- is not included in the cost estimates discussed in these chapters. These costs will depend on the number of sources that elect to engage in trading. Analysis of EGUs with the IPM indicates these costs are 1.5% of compliance costs, so they are expected to be small.

Source Type	Potentially Affected Firms/Entities	
	Total	**Small**
Industrial Boilers	108	9
Gas Turbines	7	0

[a] 3 firms own establishments that operate both types of sources.

Table 7-8
Number of Firms Potentially Affected, by Sector and Size

Sector and Size of Entity	Potentially Affected Firms/Entities
Firms	101
of which, small entities	*9*
large entities	*84*
entity size unknown [a]	*8*
Federal government	1
Other government	1
Utility (SIC 4911, 4931) [b]	7
Colleges/universities	2
TOTAL	112

[a] Unknown size refers to entities whose employee size could not be determined.
[b] These are primarily cogenerators that supply less than 50% of generated power to the electric power grid.

7.3.2 Results for the Final Alternative (60% control)

Firm/Entity-Level Impacts

Screening-level impact results at the firm level are summarized in Table 7-9. This table shows the number of potentially affected firms or entities at particular levels of firm-level costs as a percentage of firm sales, revenues or expenditures.

Table 7-9 shows that, at the firm or entity-level, only a small percentage of the potentially affected firms or entities for which sales estimates are available (3 of 102 or three percent) experience costs above one percent of sales, and these three also experience costs above three percent of sales. Of the nine affected small entities, two may experience costs of three percent of sales or greater.

EPA expects that States implementing the final Section 126 rule will take these potential impacts into account in designing their implementation scenarios.

Table 7-9
Number of Potentially Affected Firms by Firm Costs as a Percentage of Sales/Expenditures: 60% control

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Sales NA [a]	Total
Firms/Non-Profits	88	3	0	2	8	101
Of which, small entities	*5*	*2*	*0*	*2*	*0*	*9*
large entities	*83*	*1*	*0*	*1*	*8*	*84*
entity-size unknown	*3*	*0*	*0*	*0*	*8*	*8*
Federal Government [a]	na	na	na	na	1	1
Other Government [a]	0	0	0	0	1	1
Utility [b]	5	1	0	1	0	7
Colleges/Universities	2	0	0	0	0	2
TOTAL	95	4	0	3	10	112

[a] Sales not available or (for the federal government) not applicable.
[b] Co-generation units that supply less than 50% of generated power to the electric power grid.

Establishment-Level Impacts

The 112 affected firms own 147 potentially affected establishments. Establishment-level impacts provide additional insights on individual facilities, which in some cases are seen as stand-alone profit centers. Table 7-10 summarizes the results of the establishment-level analysis, by sector and firm size.

Table 7-10 shows that impacts of the final regulatory alternative are somewhat variable. The large majority of establishments (119) incur costs that represent one percent or less of estimated sales/expenditures, and of these, 110 incur costs less than 0.5 percent of sales/expenditures. Of the 10 establishments incurring costs that exceed three percent of estimated sales/expenditures, only two are owned by identified small entities. One non-federal government establishment and two utility establishments incur costs greater than three percent of revenues.

Table 7-10
Number of Establishments by
Costs as a Percentage of Value of Shipments/Expenditures
and Sector and Firm Size:
60% control

	<0.5 %	**0.5-1.0%**	**1 - 3%**	**>3%**	**Total**
Firms/Non-Profits	104	9	13	7	133
Of which, owned by small entities	*7*	*0*	*0*	*2*	*9*
owned by large entities	*92*	*9*	*10*	*5*	*116*
entity-size unknown	*5*	*0*	*3*	*0*	*8*
Federal Government [a]	na	na	na	na	4
Other Government [a]	0	0	0	1	1
Utility [b]	4	0	1	2	7
Colleges/Universities	2	0	0	0	2
TOTAL	110	9	14	10	147

[a] Revenues not available for one "other government" and 4 federal government establishments.
[b] Co-generation units that supply less than 50% of generated power to the electric power grid.

Industry-Level Impacts

Table 7-11 shows estimated impacts at the establishment level by industry (2 digit SIC code level). Table 7-11 shows that, for the most part, only a small number of establishments (usually less than 0.1 percent of the total) are potentially significantly impacted in any single industry compared to the total number of establishments for each potentially affected industry within the final Section 126 region. The 147 potentially affected establishments represent only 0.01 percent of all the establishments in the final Section 126 region (roughly 2.2 million). In most cases, impacts associated with the final Section 126 rule are unlikely to result in any significant impacts at the industry level for potentially affected industries because the number of affected establishments is a very small proportion of the total in those industries. In addition, because only very few establishments may experience potentially significant costs in each industry, the rule is not likely to result in price increases to customers of the affected firms or other indirect economic impacts. EPA has concluded that a more detailed market-level impacts analysis is not needed for any of these industries.

Table 7-11
Number of Establishments By Establishment-Level Costs
as a Percentage of Value of Shipments/Expenditures and Industry:
60% control

SIC	Industry/Sector	<0.5 %	0.5-1.0%	1-3 %	> 3%	Total	Percent of Establishments in final Section 126 Region Potentially Affected at the 2- digit SIC Code Level
20	Food and kindred products mfgr.	5	0	0	0	5	0.4
22	Textile mill products	2	1	1	0	4	0.1
24	Lumber & wood products, exc. furniture	0	0	0	1	1	<0.1
26	Paper and Allied Products	21	4	3	1	29	2.0
28	Chemicals & allied products	20	2	4	1	27	1.0
29	Petroleum refining and related industries	16	1	1	1	17	1.6
30	Rubber & plastics products	2	0	1	0	3	0.1
32	Stone, Clay, Glass and Concrete Products	1	0	0	0	1	0.5
33	Primary metals	23	1	2	1	27	0.9
34	Fabricated metal products, exc. machinery & trans. equip.	4	0	0	0	4	<0.1
35	Industrial & commerical machinery & computer equip.	2	0	0	0	2	<0.1
37	Transportation equipment	5	0	0	0	5	0.2
49	Electric, gas &	5	0	3	3	11	1.2

SIC	Industry/Sector	<0.5 %	0.5-1.0%	1-3 %	> 3%	Total	Percent of Establishments in final Section 126 Region Potentially Affected at the 2- digit SIC Code Level
51	Wholesale trade -nondurable goods	1	0	0	0	1	<0.1
72	Personal services	0	0	0	1	1	<0.1
79	Amusement and recreation services	1	0	0	0	1	<0.1
Colleges/universities		2	0	0	0	2	<0.1
Federal government [a]		na	na	na	na	4	na
Other government [a]		0	0	0	1	1	na
TOTAL		110	9	14	10	147	<0.1

[b] Includes natural gas transmission establishments (SIC 4922) and electric utilities establishments (SIC 4911). Utilities having non-EGU sources affected by these alternatives have co-generation units that supply less than 50% of generated power to the electric power grid.

[a]Revenues not available for one “other government” and 4 federal government establishments.

7.3.3 Comparison by Regulatory Alternative

Tables 7-12 and 7-13 provide an overview of economic impacts for the three combinations of regulatory alternatives considered. Table 7-12 presents results at the firm level, and Table 7-13 shows impacts at the establishment level.

Table 7-12
Number of Firms by Firm Costs as a Percentage of Sales/Expenditures and by Regulatory Alternative

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Sales NA [a]	Total
40%	97	2	1	2	10	112
Final Alternative: 60%	95	4	0	3	10	112
70%	91	4	2	5	10	112

[a] Sales not available or (for federal government) not applicable.

Table 7-13
Number of Establishments by Establishment-Level Costs as a Percentage of Value of Shipments/Expenditures and by Regulatory Alternative

	<0.5 %	0.5-1.0%	1 - 3%	>3%	Sales NA [a]	Total
40%	128	5	4	6	4	147
Final Alternative: 60%	110	9	14	10	4	147
70%	99	13	15	16	4	147

[a] Sales not available or (for federal government) not applicable.

The comparison among these regulatory alternatives shows a modest difference in potential economic impacts between the final alternative and either the least or most stringent combination of regulatory alternatives considered. Only four additional firms and 21 additional establishments may incur costs above one percent of sales/expenditures for the final alternative compared to the least stringent regulatory alternative. Applying the most stringent regulatory alternative results in an increase of four firms and seven establishments that may incur costs above one percent of sales/expenditures when compared to the final alternative.

7.4 Small Entity Impacts

This section discusses potential impacts on small entities that may be affected by requirements related to the final Section 126 rule. Since States are ultimately charged with achieving reductions to meet their emissions budgets, they should seek to minimize impacts on small entities to the maximum extent practicable. The information presented in this section may assist States in selecting control measures that minimize small entity impacts.

Table 7-14 shows potential small entity impacts for the final alternative and two other non-EGU regulatory alternatives.

Table 7-14
Number of Potentially Affected Small Entities by
Cost as a Percentage of Sales/Expenditures by Regulatory Alternative

Regulatory Alternative	Total Small Entities Potentially Affected	<1%	1-3%	>3%
40%	9	7	0	2
Final Alternative: 60%	9	7	0	2
70%	9	6	0	3

The maximum number of potentially affected small entities that may be significantly impacted under the preferred alternative is 9, as shown in Table 7-14. The data in the table also shows that only a small absolute number of small entities is predicted to incur costs above one percent in any of the regulatory alternatives. In addition, the final alternative only results in 1 additional potentially affected small entity with compliance costs greater than one percent of firm/entity sales or revenues, compared to the least stringent regulatory alternative.

7.5 Analytical Limitations and Uncertainties

Because a quantitative uncertainty bound cannot be assigned to every input, the total uncertainty in the emission reduction and cost outputs cannot be estimated. Nonetheless, individual uncertainties can be characterized to some degree.

The application of control measures and their associated costs are affected by the propensity of the emissions projection methodology to overstate or understate the state of attainment with the ozone NAAQS in specific areas.

To model the costs of achieving the regulatory alternatives examined in this chapter, control measures or techniques are selected using average cost-effectiveness as the major criterion. While the annual cost per ton figures for each control measure are adjusted for capacity size differences, these adjustments may not account well for other important cost-determining variables, such as source status (new versus retrofit), annual operating hours, equipment, materials of construction, and unit prices for materials and labor.

7.6 References

Abt Associates, 1999. *Non-Electricity Generating Unit Economic Impact Analysis for the Final Section 126 Rule*. Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, October 1999.

Pechan-Avanti Group. *Final Section 126 Petition Rulemaking Non-Electricity Generating Unit Cost Analysis.* Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1999.

Chapter 8. IMPACTS ON GOVERNMENT ENTITIES

This chapter describes the potential impacts on State and local governments and the Federal government associated with Federally-imposed requirements in the May 25, 1999 notice of final rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the findings based on the 8-hour ozone NAAQS.

Section 8.1 discusses administrative requirements imposed under the final Section 126 rule. Section 8.2 presents impacts from potential administrative costs to EPA of administering these requirements related to control of electricity generating units. Section 8.3 presents potential compliance (control and administrative) costs to potentially affected government-owned entities - including electricity generating units (EGUs) and non-electricity generating sources (non-EGUs). References are listed in Section 8.4.

8.1 Results in Brief

The expected administrative costs to State and local governments from revising Title V permits to account for the requirements of the final Section 126 program are $401,000 in 1997 dollars ($326,000 in1990 dollars) in 2001 and 2002. No costs associated with permitting will be incurred in 2007 since all permitting activities will be complete by that time. The expected administrative costs to EPA associated with administering the NOx Budget Trading Program in 2007 are $1.1 million in 1997 dollars ($900,000 in1990 dollars). The total compliance costs to government-owned sources in 2007 is estimated at $21 million in 1997 dollars ($17 million in 1990 dollars), or only about 2% of the total annual compliance cost of the rule.

In general, States and local governments will bear the costs of revising Title V permits to account for the requirements of the Section 126 program, including permitting costs relating to control equipment installed. The EPA will incur the cost of administering the trading program - data processing, certifications, permitting, and the tracking of allowances and emissions.

In addition, government-owned electricity generating units and a few other government-owned stationary sources are expected to require new controls under the final Section 126 rule. These costs include both control costs and administrative costs similar to those incurred by other regulated sources, including costs related to trading of allowances and emissions.

8.2 Administrative Requirements for Government Entities

Under the final Section 126 rule, State and local governments will be responsible for permitting activities. These costs are summarized in Section 8.2.

Under the final Section 126 rule, EPA's responsibilities will include (1) maintaining and administrating the allowance tracking system (NATS), (2) reviewing permit applications, (3) reviewing monitoring plans and certification applications, (4) processing, reviewing and evaluating reports of quarterly emissions data from affected units, (5) calculating/reviewing ozone season emissions, and (6) reviewing emissions data submitted annually to track each State's progress toward meeting its NOx budget and creating a summary report of statewide NOx emissions every three years. EPA will also answer respondent questions and conduct audits of data submissions.[1]

In the ICR, the trading sources are grouped into the following categories to estimate the burdens and costs that vary by source category:

- Trading units subject to Title IV Acid Rain monitoring requirements (40 CFR Part 75) that are located in the Ozone Transport Commission (OTC) region ("AR-OTC");
- Trading units subject to Title IV monitoring requirements that are not located in the OTC region ("AR-NOTC");
- Trading units not subject to Title IV monitoring requirements that are located in the OTC region("NAR-OTC"); and
- Trading units not subject to Title IV monitoring requirements that are not located in the OTC region ("NAR-NOTC").

The NOx Trading Program requires all affected sources to install a NOx emission rate (or concentration) continuous emissions monitor (CEM) and a flow CEM (or approved alternative). Affected gas- and oil-fired units may elect to use a NOx emissions rate CEM and a fuel flowmeter. In addition, peaking units that burn natural gas and/or fuel oil may use an alternative method for calculating NOx emission rates. EPA will also allow certain low mass emissions units to use assumed emissions factors together with operational data to calculate emissions. For some units, a change to an existing monitoring system even under an existing program may require recertification.

As discussed in Section 6.5, the burdens and costs to units will vary depending on the source type and monitoring requirements that the unit is already meeting. Similarly, the administrative costs to EPA will vary by category and unit type as shown in the ICR.

Sources will also be required to submit an annual statement providing information on which allowances are to be deducted and certifying that the unit is in compliance with the emission

[1] See the Information Collection Request (ICR) for the section 126 rulemaking.

limitations and monitoring and reporting requirements. EPA will incur administrative costs in the annual auditing of the year end compliance certifications. Sources will also be required to submit quarterly emissions data. To process, review, and evaluate these reports, EPA will incur additional administrative costs.

Before installing new control equipment and monitoring equipment, each unit may be required to obtain an construction permit. In addition, all units will be required to modify their Title V operating permits. EPA will incur costs in reviewing and approving/disapproving both the construction and Title V operating permits.

The administrative costs associated with all of the activities implemented by EPA are presented in section 8.3.

8.3 Administrative Costs Incurred by State and Local Governments

State and local governments would be responsible for revising Title V permits to account for the requirements of the final Section 126 program. In addition, they would be responsible for any permitting costs relating to control equipment installed as a result of the Section 126 program. There will be no burden associated with permitting in 2007, because all of the permitting activities will be completed by that time. The permitting activities should all take place between 2000 and 2003. The highest burden will come in both 2001 and 2002 when States will be working on both Title V permits and permits to construct. EPA anticipates a cost of $326,403 in both of those years. EPA anticipates that the entire cost associated with permitting will be $783,037.

8.4 Administrative Costs Incurred by EPA in Administering the Trading Program

This section presents the estimates of administrative costs for EPA associated with administering the trading program. The primary burdens for EPA associated with the implementation of the trading program once the program is running are related to processing emissions data, recertifying monitors, tracking allowances and emissions, and certifying end of year compliance. Table 8-1 summarizes the total annual administrative costs to EPA by activity in the year 2007. EPA will also incur costs associated with startup of the program. These include costs associated with certifying monitors, and permitting.

Table 8-1
Total Administrative Costs Associated with the Final Section 126 Rule Incurred by EPA in 2007
(thousands of 1990 $)

Administrative Activity	Other Direct Costs	Total EGU Labor Costs	Total Non-EGU Labor Costs	Total Annual Costs
Processing Emissions Data	0	$12.2	$11.2	$13.4
Monitoring Recertifications	$25	$6.4	$6.4	$37.8
Annual Auditing	$25	$6.4	$6.4	$37.8
Allowance Tracking System	$170.0	$84.5	$84.5	$339.0
Emissions Tracking System	$136.0	$169.0	$169.0	$474.0
Total	$356.0	$322.4	$321.4	$902.0

EPA estimates that the capital costs in modifying its existing Emissions Tracking System (ETS) and Allowance Tracking System (ATS), which are used to support the Federal SO_2 Trading Program under Title IV of the Act and the OTC NOx Budget Trading Program, would be $250,000 and $500,000, respectively. EPA also estimates that there would be on-going operational expenses of approximately $100,000 annually to support each system.

The remainder of the costs are agency labor and are based on the ICR for the section 126 rulemaking. EPA estimates that 1 hour will be spent processing each quarterly report. Since EPA already receives quarterly reports from units subject to both the Acid Rain Program and the OTC Program, this will only include quarterly reports received from sources not subject to either of these programs. In addition to costs for processing quarterly reports, EPA estimates that 4 additional full time equivalents (FTEs) will be devoted to additional activities related to running the emissions tracking system and that 2 additional FTEs will be devoted to additional activities related to running the allowance tracking system. EPA anticipates that 10% of the units will have a recertification event each year and that 10 hours will be spent reviewing each recertification which will result in a total annual cost of $12,800. EPA anticipates similar costs for auditing. EPA also anticipates some other direct costs related to recertification and auditing.

In summary, the total costs for the Agency associated with EGUs is expected to be approximately of $902,000 in 2007.

In the years 2000 through 2002 EPA will also have additional tasks associated with certifying monitors and reviewing permits, so EPA's costs may be higher in those years. In 2000 and 2001 this is counteracted by the fact that all of the program requirements will not be implemented in those years (e.g. not all units will have to submit quarterly reports).

8.5 Government-Owned Entities

This section summarizes compliance costs incurred by government-owned electricity generating units and other stationary sources that are assumed to require new controls under the final Section 126 rule. These costs include both control costs and administrative costs similar to those incurred by other regulated sources, including costs associated with trading. These costs are a subset of the compliance costs presented in Chapter 6 for EGUs and in Chapter 7 for non-EGUs (industrial boilers and combustion turbines). The control costs are based on IPM projections and assumptions of how affected States and municipalities will implement control measures to comply with NOx emission limits set forth in this rule. Additional analyses of the impacts of the final rule on State- and municipality-owned electric utilities are presented in U.S. EPA, *Unfunded Mandates Reform Act Analysis for the Section 126 Petitions Rule Under the Clean Air Act Amendments Title I* (U.S. EPA, 1999a).

Table 8-2 provides an overview of the government entities which own EGUs that may be affected by the 0.15 trading alternative.

Table 8-2
2007 Annual Costs To Potentially Affected Government-Owned EGU NOx Emissions Units: 0.15 Trading Alternative

Government Entity	Number of Units	Annual Control Costs (thousands of 1990$)	Annual Administrative Costs (thousands of 1990$)	Total Compliance Costs (thousands of 1990$)
Federal Government[a]	na	na	na	na
State and Municipal Government	43	$14,930	$185	$15,115
TOTAL:	43	$14,930	$185	$15,115

[a] Control and administrative costs were not estimated for these sources. One Federal utility, the Tennessee Valley Authority, is subject to the requirements of the section 126 rule. Estimating the compliance costs for these utilities requires more data than is available.

As shown in Table 8-2, there are 43 potentially affected State- and municipality-owned EGUs that may be affected under the 0.15 trading alternative. These units may experience compliance costs of about $15 million in 2007. One Federal utility, the Tennessee Valley Authority, will incur costs as a result of the final Section 126 rule. These costs are included in the total costs assessed in Chapter 6, but are not disaggregated for this analysis.

Table 8-3 provides an overview of the government entities which own non-EGUs that may be affected under the selected alternative (60% control). As shown in Table 8-3, there are 7 potentially affected government-owned non-EGU sources that may experience compliance costs of roughly $1.7 million dollars in 2007.

Table 8-3
2007 Annual Costs To Potentially Affected Government-Owned Non-EGU NOx Emissions Sources: 60% control

Government Entity	Number of Sources	Annual Control Costs (thousands of 1990$)	Annual Administrative Costs (thousands of 1990$)	Total Compliance Costs (thousands of 1990$)
Federal Government	4	$54	$13	$67
Educational institution	2	1,394	251	1,645
City, regional sewerage systems	1	69	4	73
TOTAL:	7	$1,517	$268	$1,785

Therefore, under the 0.15 trading alternative for EGUs and the 60% control alternative for non-EGUs, 50 sources or units owned by Federal, State, and local governments in the section 126 region may potentially be affected by control and administrative measures at an annual compliance cost of about $17 million in 2007. This compliance cost, however, is only 1.7 percent of the total compliance cost for these alternatives ($1 billion in 1990 dollars).

8.6 References

Abt Associates, 1999. *Non-Electricity Generating Unit Economic Impact Analysis for the Final Section 126 Petition Rulemaking.* Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, October 1999.

U.S. Environmental Protection Agency, 1998a. *ICR # 1857.01*, *Emission Reporting Requirements for Ozone SIP Revisions Relating to Statewide Budgets for NOx Emissions,* September 1998.

U.S. Environmental Protection Agency, 1998b. ICR # 1857.02, *Emission Reporting Requirements for the Federal Implementation Plans for NOx Emissions,* September 1998.

U.S. Environmental Protection Agency, 1998c. ICR #1889.01, *Information Collection Request for Finding of Significant Contribution and Rulemaking Action on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport*, September 1998.

U.S. Environmental Protection Agency, 1999a. *Unfunded Mandates Reform Act Analysis for the Section 126 Petitions Rule Under the Clean Air Act Amendments Title I.* Office of Air and Radiation, November 1999.

Chapter 9. Integrated Cost, Emissions, And Small Entity Impacts Summary

This chapter presents EPA's estimates of the NOx emission reductions, potential compliance costs, average cost-effectiveness, and potential small entity impacts associated with the final Section 126 rule. It brings together the results presented in Chapters 6, 7, and 8 of this RIA. All of these results are based on how States in the final Section 126 region would implement control strategies to meet the NOx budget levels set for them in this rulemaking. The results are then compared to average cost-effectiveness estimates of other recent regulatory actions that require NOx reductions.

Section 9.1 presents a summary of the results integrated across EGUs and non-EGUs. Section 9.2 presents estimates of NOx emission reductions for potentially affected electricity generating units (EGUs) and non-electricity generating sources (non-EGUs). Section 9.3 presents estimates of compliance costs (control and administrative costs) and average cost-effectiveness for all these sources. Section 9.4 provides a table of average cost-effectiveness estimates for other recent regulatory actions that require NOx reductions so that comparisons across rules can be made. Section 9.5 presents an integrated summary of potential small entity impacts. The list of references for this chapter is in Section 9.6.

This chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). This final notice presented the final Section 126 remedy (0.15 trading- utilities; 60% control- industrial boilers and combustion turbines). It should be noted that the results primarily reflect application of the final Section 126 remedy to all sources in a named source category in each State in the final Section 126 region. The results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS. Costs are expressed in 1990 dollars, but are summarized in 1997 dollars in Section 7.1 for ease of comparison with the costs of the final Tier 2 rule and prospective Section 812 study.

9.1 Results in Brief

The NOx emissions reductions in 2007 expected across the spectrum of regulatory alternatives examined in the report ranges from 411,000 tons to 739,000 tons. For the final alternatives (0.15 trading - EGUs, 60% control - non-EGUs), the emissions reductions are estimated to be 659,000 tons. The annual compliance costs in 2007 of these regulatory alternatives applied across the final Section 126 region ranges from $529 million to $1,602 million in 1997 dollars (or $430 million to $1,301 million in 1990 dollars). For the final alternatives, the annual compliance costs in 2007 are estimated to be $1,171 million in 1997 dollars ($951 million in 1990 dollars). The average cost-effectiveness of these regulatory alternatives combined across affected EGUs and non-EGUs ranges from $1,288/ton to $2,167/ton in 1997 dollars ($1,046/ton to $1,760/ton in 1990 dollars). For the final alternatives, the average cost-effectiveness of control across affected EGUs and non-EGUs is $1,776/ton in 1997 dollars ($1,443/ton in 1990 dollars). There are 88 small entities potentially affected by the final alternatives for EGUs and non-EGUs, and 16 of them are estimated to have annual compliance costs greater than 1 percent of their sales or revenues.

9.2 Emission Reductions

With this rulemaking, EPA will establish 2007 ozone season NOx budgets for 12 States and the District of Columbia based on emissions reductions from electricity generating units, industrial boilers and combustion turbines.[1] This analysis of impacts uses a baseline that includes the existing Title IV NOx rules, Reasonably Available Control Technology (RACT) requirements, New Source Performance Standards (NSPS) and controls for new and recently-built major NOx sources. The baseline also includes implementation of Phase I (RACT requirements) of the Ozone Transport Commission (OTC) Memorandum of Understanding (MOU)[2].

Table 9-1 shows the NOx emissions levels and emissions reductions for selected combinations of alternatives that EPA has analyzed for affected electricity generating units and non-electricity generating sources. These results bring together the four regulatory alternatives analyzed for potentially affected EGUs and the four regulatory alternatives analyzed for non-electricity generating sources. These alternatives are discussed in Chapter 2 and the results of the analyses are presented in Chapters 6 and 7. The alternatives selected for the final Section 126 rule are highlighted.

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[1] Process heaters is a source category named in the 8 final Section 126 petitions, but EPA estimated that controls for this source category did not fall within the Agency's framework for highly cost-effective emissions reductions ($2,460/ton in 1997 dollars; $2,000/ton in 1990 dollars). Therefore, no impacts to process heaters are presented in this chapter. Refer to chapter 7 for results of the cost analysis for process heaters.

[2] This baseline is discussed in greater detail in Chapter 4.

Table 9-1
2007 Ozone Season NOx Emissions and Emission Reductions for Selected Combinations of Electricity Generating Units and Non-Electricity Generating Source Regulatory Alternatives from the Initial Base Case [a]
(thousands of NOx Tons)

Regulatory Alternatives		Electricity Generating Units (941 thousand baseline tons)			
		0.25 Trading	**0.20 Trading**	**0.15 Trading**	**0.12 Trading**
Non-Electricity Generating Sources (90 thousand baseline tons)	**40% Control**	620 (411)	506 (525)	393 (638)	325 (706)
	50% Control	609 (422)	495 (536)	382 (649)	314 (717)
	60% Control	599 (432)	485 (546)	**372 (659)**	304 (727)
	70% Control	587 (444)	473 (558)	360 (671)	292 (739)

[a] Emissions reductions are shown in parentheses. The emissions remaining after application of the given control alternatives are also shown. Control on the electricity generating units occur through a cap-and-trade program described in the Federal NOx Budget Trading Program and supporting information. Controls on non-electricity generating sources are applied using a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines. Analytical limitations prevented EPA from estimating the emission reductions of a single cap-and-trade program for electricity generating units and large industrial boilers and combustion turbines combined.

9.3 Compliance Costs and Cost-Effectiveness

Table 9-2 shows annual compliance costs for selected combinations of regulatory alternatives that EPA has analyzed for potentially affected electricity generating units and non-electricity generating sources. Costs include direct control costs and administrative costs (monitoring, recordkeeping, and reporting). The alternatives selected for the final Section 126 rule are highlighted. The costs for EGUs reflect emissions trading across States. For non-EGUs, costs are determined using a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines.

Table 9-3 provides the resulting 2007 ozone season average control cost-effectiveness values for the same selected combination of alternatives examined in the previous two tables. The average control cost-effectiveness of ozone season NOx emission reductions is calculated as the change in total annual compliance costs relative to the Initial Base case divided by the change in ozone season NOx emissions relative to the Initial Base case. This table shows the increase in average cost-effectiveness values as the combination of standards considered becomes more stringent. It should be noted that these estimates are only presented to illustrate the average cost-effectiveness of different combinations of EGU and non-EGU alternatives. The decisions on control levels and the inclusion of individual source categories in this rulemaking were made by evaluating each category separately, not by using the summary of cost-effectiveness values in Table 9-3.

The Ozone Transport Assessment Group (OTAG) recognized the value of market-based approaches to lowering emissions from power plants and large industrial sources. The Agency agrees that using a market-based approach in the emission reduction program is desirable. Accordingly, the Agency is issuing the final Federal NOx Budget Trading Program. This rule provides for an emissions cap and allows for trading between sources in the all the jurisdictions covered, which are essential for this rule to be effective and administratively practicable. The Agency wants to work with all affected jurisdictions covered by this rulemaking to establish such a program. This is a major reason behind the Agency's effort to estimate NOx control costs across the jurisdictions in the final Section 126 region for electric power generation units and cost minimization across the same domain for the non-electricity generating sources. Analytical limitations kept EPA from estimating the costs of a single cap-and-trade program for electricity generating sources and large industrial sources in the non-electricity generating source category (e.g., industrial boilers and combustion turbines). Given that the Agency could not estimate the costs of a single emissions trading program for these sources, the annual cost estimates for this rulemaking are likely to be overstated to the extent that costs could be reduced by trading between facilities in both groups.

Table 9-2
2007 Annual Final Section 126 Compliance Costs for Selected Combinations of Electricity Generating Unit and Non-Electricity Generating Source Regulatory Alternatives (millions of 1990 dollars)[a]

Regulatory Alternatives		Electricity Generating Units			
		0.25 Trading	**0.20 Trading**	**0.15 Trading**	**0.12 Trading**
Non-Electricity Generating Sources	**40% Control**	$430	$628	$912	$1,192
	50% Control	$444	$642	$926	$1,206
	60% Control	$469	$667	**$951**	$1,231
	70% Control	$539	$737	$1,021	$1,301

[a] The decisions on control stringency and the inclusion of individual source categories in this rulemaking were not made using the summary of cost-effectiveness values in this table. Control on the electricity generating units occur through a cap-and-trade program described in the Federal NOx Budget Trading Program and supporting information. Controls on non-electricity generating sources are applied using a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines. Analytical limitations prevented EPA from estimating the costs of a single cap-and-trade program for electricity generating units and large industrial boilers and combustion turbines combined. Costs for these sources are likely to be lower than those that have been estimated in this RIA if States integrate electricity generating units and industrial boiler and combustion turbine programs into a single trading program. It should be noted that individual States may decide to achieve their NOx budget with other control techniques, thereby affecting their costs.

Table 9-3
2007 Ozone Season Average Compliance Cost-Effectiveness for Selected Combinations of Electricity Generating Unit and Non-Electricity Generating Source Regulatory Alternatives
(1990 dollars per ton of NOx reduced in the ozone season)[a]

Regulatory Alternatives		Electricity Generating Units			
		0.25 Trading	**0.20 Trading**	**0.15 Trading**	**0.12 Trading**
Non-Electricity Generating Sources	**40% Control**	$1,046	$1,196	$1,429	$1,688
	50% Control	$1,052	$1,198	$1,427	$1,682
	60% Control	$1,086	$1,222	**$1,443**	$1,693
	70% Control	$1,214	$1,321	$1,522	$1,760

[a]Controls on the electricity generating units occur through a cap-and-trade program described in the Federal NOx Budget Trading Program and supporting information. Controls on non-ele ctricity generating sources were applied using a least-cost approach that approximates a trading program, applied to large industrial boilers and combustion turbines. Analytical limitations prevented EPA from estimating the costs of a single cap-and-trade program for electricity generating units and large industrial boilers and combustion turbines combined. Costs for these sources are likely to be lower than those that have been estimated in this RIA if States integrate electricity generating units and industrial boiler and combustion turbine programs into a single trading program. It should be noted that individual States may decide to achieve their NOx budget with otheer control techniques, thereby affecting their costs.

9.4 Cost-Effectiveness Comparisons

Table 9-4 provides a reference list of measures that EPA and the States have undertaken to reduce NOx and their average cost per ton of NOx reduced. The average annual cost per ton of NOx reduced from this rulemaking is included in the table. Most of these measures fall in the $1,000 to $2,000 per ton (1990 dollars) range. With few exceptions, the average cost-effectiveness of these measures is representative of the average cost-effectiveness of the types of controls EPA and the States have needed to adopt most recently since their previous planning efforts have already taken advantage of opportunities for even cheaper controls. The Agency believes that the cost-effectiveness of measures that it or States have adopted, or propose to adopt, forms a good reference point for determining which of the available additional NOx control measures can most reasonably be interpreted by upwind States or jurisdictions that significantly contribute to ozone nonattainment.

Table 9-4
Average Cost-Effectiveness of NOx Control Measures
Recently Undertaken or Proposed (1990 dollars)

Control Measure	Average Cost per Ton of NOx Reduced
NOx RACT	$150 - 1,300
Phase II Reformulated Gasoline	$4,100[a]
State Implementation of the Ozone Transport Commission Memorandum of Understanding (OTC MOU)	$950 - $1,600
Proposed New Source Performance Standards (NSPS) for Fossil Steam Electric Generating Units	$1,290
Proposed NSPS for Industrial Boilers	$1,790
Final NOx SIP Call Rulemaking - Electricity Generating Units	$1,468[b]
Final NOx SIP Call Rulemaking - Other Stationary Sources	$1,365[c]

[a] Average cost representing the midpoint of $2,180 to $6,000 per ton, as described in EPA's response to the American Petroleum Institute's petition to waive the Federal Phase II RFG NOx standard. This cost represents the projected additional cost of complying with the Phase II RFG NOx standards, beyond the cost of complying with the other standards for Phase II RFG.
[b] Estimated average cost-effectiveness (including compliance costs) associated with the uniform 0.15 trading alternative.
[c] Estimated average cost-effectiveness (including compliance costs) associated with the final alternative (60% control - industrial boilers and combustion turbines).

There are also a number of less expensive measures recently undertaken by the Agency to reduce NOx emissions that do not appear in Table 9-4. These actions include: (1) the Title IV NOx reduction program, (2) the federal locomotive standards, (3) the 1997 proposed federal nonroad diesel engine standards, (4) the federal heavy duty highway engine 2g/bhp-hr standards, and (5) the federal marine engine standards. These actions do not provide a meaningful comparison to this rulemaking because they are believed to be among the lowest cost options for NOx control. Since these options have been exhausted, the Agency must now focus on what other measures can further reduce NOx emissions even if they have potentially high average cost-effectiveness values. Table 9-4 is thereby useful as a reference for the next level of NOx reduction cost-effectiveness that the Agency considers reasonable to undertake.

9.5 Consideration of 2007 SO_2 Emissions

For most of the comparisons in Chapter 6 and 7 of this RIA, results are presented only in year 2007. However, as discussed below, 2007 is not an appropriate year to estimate the benefits (presented in Chapter 11) of this final Section 126 rule.

Selection of 2007 as the analytical year for the benefits analysis resulted in SO_2 emissions and air quality results that are not representative of the expected change in air quality for pr rain permit program, SO_2 emissions can increase in some years and decrease in others as long as net SO_2 emissions do not change over a specified time horizon. The 2007 analytical year is a year when there are particularly high levels of permit withdrawals (due to shifting in electricity generation and adoption of technologies that use high sulfur coal), such that SO_2 emissions in 2007 increase relative to baseline levels. In most other years, SO_2 emissions decrease, so 2007 represents a “worst case” year with respect to the change in SO_2 emissions. To account for this, we have constructed a “Representative Year” (in terms of SO_2 emissions) scenario by zeroing out all changes in sulfates, both positive and negative, in calculating the changes in $PM_{2.5}$. Changes in $PM_{2.5}$ are then driven solely by changes in nitrate concentrations. EPA believes that this “Representative Year” scenario is a closer approximation to the expected annual benefits of the Section 126 rule.

In addition to the “Representative Year” scenario, EPA has constructed two scenarios representing different SO2 banking possibilities. These scenarios are intended to provide a balanced picture of the types of benefits that may be realized in particular years with either net withdrawals or net banking of SO2 permits. The first of these scenarios represents a “SO2 Increasing” year, based on the 2007 “as is” SO2 emissions estimates (i.e. net increases in SO2). The second scenario represents a “SO2 Decreasing” year, based on 2004 predicted SO2 emissions (i.e. net decreases in SO2). Both of these scenarios allow for both increases and decreases in sulfates at the county level.

The costs for 2004 should differ relatively little from those estimated for 2007. Estimates of EGU costs shown in Chapter 6 indicate relatively little variation in annual costs between 2003 and 2010 ($1,092 million in 2003, and $1,192 million in 2010 - in 1997 dollars). Estimates of non-EGU costs are only available for 2007, but it is unlikely these costs, which are only 8 percent of the overall compliance costs, should vary greatly from year to year. Thus, this "Representative Year" scenario has little or no impact on the cost analysis in this RIA.

9.6 Integrated Small Entity Impacts

The Agency examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected States will implement control measures to meet their NOx budgets. While the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) does not apply to this action, these impacts have been calculated in order to provide additional understanding of the nature of potential impacts, and additional information to the States as they prepare State Implementation Plans (SIPs) designed to meet the NOx budgets set by this rulemaking. The Agency has therefore prepared a Final Regulatory Flexibility Analysis (FRFA) for this rule.

Table 9-5 presents a summary of the potentially affected small entities in EPA's analysis. Of the 88 small entities potentially affected, 16 may experience compliance costs in excess of one percent of revenues, based on assumptions of how the affected States implement control measures to meet their NOx budgets as set forth in this rulemaking (U.S. EPA, 1999c). Potentially affected small entities experiencing compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the final Section 126 rule. These 16 small entities constitute about 4 percent of the small entities in the final Section 126 region that own sources potentially affected by this rulemaking.

EPA expects that States implementing the final Section 126 rule will take these potential impacts into account in designing their implementation strategies. Since States are ultimately charged with achieving reductions to meet their emissions budgets, they should seek to minimize impacts to small entities to the maximum extent practicable. The information presented in this section may assist States in selecting control measures that minimize small entity impacts.

Chapter 6 includes EPA's estimates of other potential economic impacts for entities owning electricity generating units including changes in capacity, as well as changes in demand for electricity that could result from implementation of the final Section 126 rule. Details on EPA's other estimates of potential economic impacts to entities owning sources in the non-electricity generating source category are found in Chapter 7.

Table 9-5
Number of Potentially Affected Small Entities for the final Section 126 Rule

Source Category/ Regulatory Alternative	Small Entities in the final Section 126 Region	Small Entities Potentially Affected[a]	Small Entities in the final Section 126 Region with Compliance Costs > 1% of Sales/Revenues	Percentage of Small Entities in the final Section 126 Region with Compliance Costs > 1% of Sales/Revenues
Electricity Generating Units: 0.15 Trading	179	80	14[b]	8%
Non-Electricity Generating Sources: 60% Control	200[c]	8	2	1%
TOTAL:	379	88	16	4%

[a]These are small entities that own large sources in the source categories covered under this rulemaking.
[b] The estimated costs of compliance are calculated assuming all small non-utility generators comply through purchasing allowances. This approach tends to overstate compliance costs because cases in which emission reductions can be achieved below the marginal cost of reductions in the final Section 126 region are not considered.
[C] This represents the number of small entities in the final Section 126 region owning sources (small and large) in the source categories covered under this rulemaking.

9.7 References

U.S. Environmental Protection Agency, 1999a. *Non-Electricity Generating Unit Economic Impact Analysis for the Final Section 126 Petition Rulemaking Under the Clean Air Act.* October, 1999.

U.S. Environmental Protection Agency, 1999b. *Final Regulatory Flexibility Analysis for the Final Section 126 Petition Rulemaking.* April, 1999.

U.S. Environmental Protection Agency, 1999c. *Final Small Entity Screening Analysis for the Section 126 Petitions Rulemaking.* October, 1999.

Chapter 10. Air Quality Impacts

10.1 Results in Brief

This chapter provides results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The final notice presented the Section 126 remedy (0.15 trading - utilities; 60% control - industrial boilers and combustion turbines). It should be noted that the results primarily reflect application of the Section 126 remedy to all sources in a named source category in each State in the final Section 126 region. The results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the affirmative technical determinations based on the 8-hour ozone NAAQS.

Air quality changes in ambient ozone, coarse and fine particulates, airborne nitrogen deposition, and visibility (i.e., regional haze) are calculated for the selected Section 126 regulatory alternative (0.15 trading) under the three scenarios introduced in Chapter 9, i.e., “SO2 increasing”, “Representative”, and “SO2 decreasing.” For our “Representative” scenario, this rule reduces ambient concentrations of PM and airborne nitrogen deposition and slightly improves visibility. We were unable to provide quantified estimates for ambient concentrations of ozone by the signature date for this rulemaking. These estimates will be available in January 2000 in a supplementary volume to this RIA. The methods for estimating air quality for the final Section 126 rule and a more detailed analysis of the results are presented below.

10.2 Introduction

This section summarizes the methods for and results of estimating air quality for the 2007 base case and the 2007 control scenario for the Section 126 Rule. EPA has focused on the air quality changes that have been linked to health, welfare, and ecological effects. These air quality changes include the following:

1. Ambient ozone–as estimated using a regional-scale version of the Urban Airshed Model (UAM-V),

2. Ambient particulate matter (PM_{10} and $PM_{2.5}$)–as projected from a Source-Receptor Matrix (S-R Matrix) based on the Climatological Regional Dispersion Model (CRDM),

3. Airborne nitrogen deposition–as predicted using local and regional coefficients of

nitrogen deposition for selected estuaries from the Regional Acid Deposition Model (RADM) in combination with modeled reduction in NOx emissions, and

4. Visibility degradation (i.e., regional haze), as developed using empirical estimates of light extinction coefficients and efficiencies in combination with modeled reductions in pollutant concentrations.

These air quality estimates are based on the emission changes presented in Chapter 9. Using the methods identified and described in Chapter 11, the air quality impacts listed above are then associated with human populations and ecosystems to estimate changes in health and welfare effects.

The final Section 126 rule is expected to result in significant NOx reductions in the Eastern United States. However, due to the NOx trading program, some localized increases in SO2 emissions relative to predicted levels without the rule are predicted to occur in 2007, our selected analytical year. These increases occur because the banking provisions in the Title IV Acid Rain permit program that caps total emissions of SO2 allow SO2 emissions to vary over time with higher emissions in some years being offset by lower emissions in other years. Given the anomalous nature of the SO2 emissions increase in 2007 (SO2 emissions decrease in every other year), we present air quality modeling results for each of the three SO2 emissions banking scenarios, as introduced in Chapter 9.

Section 10.3 describes the emissions inputs to the air quality modeling. Section 10.4 discusses the estimation of ozone air quality using UAM-V, while Section 10.5 covers the estimation of PM air quality using the CRDM S-R Matrix. Section 10.6 discusses the estimation of nitrogen deposition. Section 10.7 covers the estimation of visibility degradation. Lastly, Section 10.8 summarizes the uncertainty related to air quality modeling for this particular analysis.

10.3 2007 Emissions Inputs

The initial step in the assessment of changes in air quality attributable to each regulatory alternative is the development of future year 2007 emissions estimates. These estimates generally start off with 1996 emissions data, which are then grown to 2007. Table 10-1 identifies the emissions inputs used for the air quality models. These include nitrogen oxides (NOx), volatile organic compounds (VOC), sulfur dioxide (SO_2), directly emitted particulate matter (primary PM_{10} and $PM_{2.5}$), carbon dioxide (CO), and ammonia (NH_3). Emissions are estimated only for the geographic area covered by each air quality modeling domain, which in each case is roughly equivalent to the 37 easternmost states. Air quality estimation is not restricted to the smaller SIP call region because the SIP call regulatory alternatives may result in shifts in power generation, and hence shifts in emissions, among utility sources located inside and outside the SIP call domain. The broad 37 state area modeled for air quality purposes more clearly captures the effects of any modeled shifts in power generation. All emissions estimates were developed using information that was accurate as of August 1999, at the time that final Section 126 call emissions inventories (developed as part of the NOx SIP call emissions inventory revisions) and control alternatives were established.

The subsections that follow briefly describe emissions development for each emissions sector, including electricity generating utility point sources, other stationary point sources, area and non-road mobile sources, highway mobile sources, and non-anthropogenic sources. A final subsection identifies differences between the air quality modeling emissions inventory and the final emissions inventory, and discusses the implications for interpreting the air quality results used in this analysis.

Table 10-1. Emissions Inputs for Air Quality Models

Air Quality Model	Emissions Inputs
UAM-V	typical summer day hourly VOC and NOx
S-R Matrix	annual NOx, SO_2, CO, VOC, NOx, primary PM_{10}, primary $PM_{2.5}$, and NH_3

10.3.1 Electricity Generating Unit Point Source Emissions

EPA developed projections of 2007 NOx and SO_2 emissions from electricity generating units (EGUs) using the latest version of the Integrated Planning Model (U.S. EPA, 1998a). The CO and VOC profiles for each EGU are added based on data from EPA's National Emission Trends (NET) inventory projections. Primary PM_{10} and primary $PM_{2.5}$ are derived using IPM-generated ash content data and the latest AP-42 emission factors (U.S. EPA, 1998c). AP-42 emission factors are also used to derive NH_3 emissions. These emissions estimates are made for the 2007 base case and each control alternative.

10.3.2 Non-EGU Point Source Emissions

EPA developed projections of 2007 NOx and VOC emissions for these sources using information gathered by the Ozone Transport Assessment Group in 1997. These projections were later revised based on more recent information, including public comments submitted in response to NOx SIP call inventory correction notices issued on January 13, 1999 and May 14, 1999. Emissions of SO_2, primary PM_{10}, primary $PM_{2.5}$, and NH_3 are taken from EPA's 1996 NET projections[1]. These emissions estimates are made for the 2007 base case and each control alternative.

10.3.3 Area and Mobile Source Emissions

All area source, non-road mobile source, and highway mobile source emissions are taken directly from EPA's 1996 NET projections. Emissions are developed for all counties and then allocated to UAM-V and RADM grid cells. Additional reductions in area and mobile source emissions are not part of the control alternatives, therefore emissions estimates are made for these source categories only for the 2007 base case.

10.3.4 Natural Emissions

Natural emissions come from geogenic, biogenic, and wild fire sources. For some pollutants, natural emissions comprise a significant fraction of total emissions. For example, man-made emissions of ammonia are a small component of total ammonia emissions. The majority of the ammonia that enters the atmosphere is produced by the biological decomposition of organic material in soils, plant residues, and wastes from animals and humans (NAPAP, 1991). Biogenic VOC emissions are developed based on EPA's Biogenic Emissions Inventory System (BEIS) (Pierce et al., 1990). Natural sources of PM emissions (i.e., wind erosion) are taken from the 1996 NET. Additional reductions in natural emissions are not part of the control alternatives, therefore emissions estimates for these sources are made only for the 2007 base case.

10.3.5 Summary of 2007 Emissions Projections

Table 10-2 summarizes the major control requirements that are accounted for in the 2007 Base Case emissions projection. These include all federal motor vehicle controls and nonattainment area (NAA)-related controls required by the Clean Air Act, additional reductions from large stationary NOx sources required by the Ozone Transport Commission in the northeast U.S., and a national low emission vehicle (NLEV) standard starting in model year 1999. The control requirements included in the alternative policy scenarios modeled for air quality purposes, and hence

[1] EPA's NET does not currently include estimates of primary $PM_{2.5}$. Primary $PM_{2.5}$ emissions are estimated from primary PM_{10} emissions using regionally derived relationships between PM_{10} and $PM_{2.5}$.

for the purpose of estimating benefits, are identical to those examined in the cost and economic impacts analyses summarized in Chapters 6 and 7 of this RIA.

Table 10-3 presents the percentage change in emissions for EGU and non-EGU sources from the 2007 base case for the final regulatory alternatives for this rule. The percentage changes for these sources reflected in this table accounts for only those emissions that are input to the S-R matrix. A summary of the emissions inputs to the UAM-V ozone air quality model will be presented in a supplementary volume to this RIA.

Table 10-2. 2007 Base Case Projection Control Requirements by Major Sector

Major Sector	Major Base Case Requirements
EGU Point Sources	Title IV Phase I and Phase II NOx and SO_2 limits for all boiler types. 250 ton Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) for NOx, NO_2, VOC, CO, and SO_2. RACT and New Source Review (NSR) NOx limits for all non-waived NAAs. Phase I of the Ozone Transport Commission (OTC) NOx memorandum of understanding (MOU).
Non-EGU Point Sources	VOC and NO_x RACT for all NAAs (except NOx waivers). New control technique guidelines (CTGs) for VOC. OTAG Level 2 NOx controls across OTAG States. MACT standards (primarily affects VOC).
Area Sources	VOC and NOx RACT requirements. New CTGs for VOC. MACT Standards (primarily affects VOC). PM_{10} NAA controls. Onboard vapor recovery (vehicle refueling--VOC). Stage II vapor recovery systems (VOC). Federal rules (consumer/commercial product limits, architectural and industrial maintenance (AIM) coating limits) (VOC).
Nonroad Mobile Sources	Federal Tier 2 and 3 $\geq$50 hp compression ignition (CI) engine standards (VOC, NOx, PM). Federal Tier 1 and 2 < 50 hp CI engine standards. Federal Phase 1 and 2 small (<1.9 kw) spark ignition (SI) engine standards (CO,VOC, NOx, PM). Federal locomotive standards (VOC, NOx, PM). Federal $\geq$50 hp CI marine engine standards (VOC, NOx, PM). Federal spark ignition recreational marine engine standards (VOC, NOx, PM).
Highway Mobile Sources	Tier 1 tailpipe standards (CO, VOC, NOx, PM). 49-State (national) LEV program (CO, VOC, NOx, PM). 2004 heavy duty diesel (HDD) engine standards (NOx, VOC) Phase 2 Reid vapor pressure (RVP) limits (CO, NOx, VOC). I/M programs for ozone (VOC, NOx) and carbon monoxide (CO) NAAs. Federal reformulated gasoline for O_3 NAAs (CO, VOC, NOx, SO_2). Diesel fuel sulfur content limits (SO_2). Oxygenated fuel in CO NAAs (CO). Onboard refueling vapor recovery (VOC). Stage 2 refueling vapor recovery (VOC). Enhanced evaporation emission standards (VOC).

Table 10-3. Percent Change from 2007 Base Case in 37-State NOx Emissions

Major Sector	**0.15 Trading (EGU) + 60% control (non-EGUs)**
Annual NOx Corresponding to S-R Matrix Inputs	
EGU Sources	13.9%
Non-EGU Sources	12.9%
Total Point Sources	13.5%

10.4 Ozone Air Quality Estimates

EPA used a regional-scale version of UAM-V with the emissions presented in Chapter 9 to estimate ozone air quality. UAM-V was the primary modeling tool relied upon by the OTAG process that provided the foundation for the air quality modeling conducted for NOx SIP call. Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, the UAM-V is useful for evaluating the impacts of the final Section 126 rule on U.S. ozone concentrations. Our analysis applies the modeling system for a base-year of 1995 and for two future-year scenarios: a 2007 base case and a 2007 policy scenario. As discussed later, we used the 1995 base-year model predictions in conjunction with ambient air quality observations from 1995 to calibrate the model.

The UAM-V modeling system requires several input files that contain information pertaining to the modeling domain and simulation period. These include gridded, day-specific emissions estimates and meteorological fields, initial and boundary conditions, and land-use information. To apply the model, EPA divided the continental United States into two regions: East and West. Each region is segmented into grids, each of which has several layers of air conditions that are considered in the analysis. Using this data, the UAM-V model generates predictions of hourly ozone concentrations for every grid. EPA used the results of this process to develop future year ozone profiles at monitor sites by applying derived adjustment factors to the actual 1995 ozone data at each monitor site. For areas (grids) without ozone monitoring data, we interpolated ozone values using data from monitors surrounding the area. After completing this process, we calculated daily and seasonal ozone metrics as inputs for the health and agriculture end points of the benefits analysis. The following sections provide a more detailed discussion of each of the steps in this evaluation and a summary of the results.

10.4.1 Modeling Domain

The modeling domain representing the eastern U.S. is the same as that used in EPA's "Regulatory Impact Analysis for the NO_x SIP Call, FIP, and Section 126 Petitions" (EPA, 1998d). This domain encompasses most of the eastern U.S. and consists of two grids, as illustrated in Figure 10-1. The shaded area of Figure 10-1 uses a relatively fine grid of 12 km consisting of seven vertical layers. The unshaded area of Figure 10-1 has less resolution, as it uses a 36 km grid consisting of five vertical layers. The vertical height of the modeling domain is 4,000 meters above ground level, for both the shaded and unshaded regions.

10.4.2 Simulation Periods

A simulation period, or episode, consists of meteorological data characterized over a block of days that are used as inputs to the air quality model. A simulation period is selected to characterize a variety of ozone conditions including some days with high ozone concentrations in one or more portions of the U.S. and observed exceedances of the 1-hour NAAQS for ozone being recorded at monitors. This study used one of the four OTAG multi-day simulation periods to prepare the future-year ozone profiles, that is, 7-18 July 1995. This episode included a 2B3 day "ramp-up" period to initialize the model, i.e., July 7-9, 1995. Predictions for the ramp-up periods were not used in any portion of this analysis.

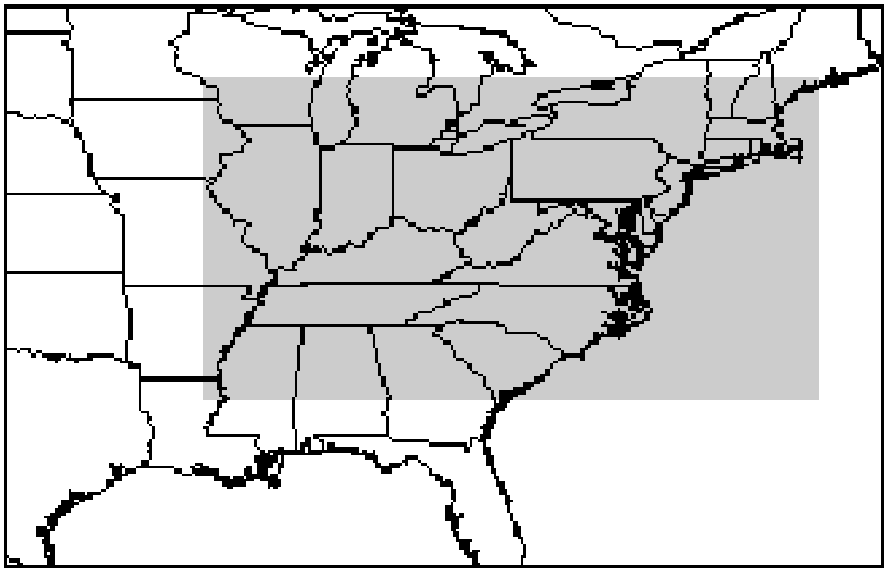

Figure 10-1. UAM-V Modeling Domain for Eastern U.S.

10.4.3 Converting UAM-V Estimates to Full-Season Profiles for Benefits Analysis

This study extracted hourly, surface-layer ozone concentrations for each grid-cell from the standard UAM-V output file containing hourly average ozone values. These model predictions are used in conjunction with the observed 1995 concentrations as obtained from the Aerometric Information Retrieval System (AIRS) to generate ozone concentrations for the entire ozone season.[2,3] The predicted changes in ozone concentrations from the 2007 basecase to 2007 policy scenario serve as inputs to the health and welfare concentration-response (C-R) functions of the benefits analysis, i.e., the Criteria Air Pollutant Modeling System (CAPMS). In order to estimate ozone-related health and welfare effects for the entire United States, full-season ozone data is

[2] The ozone season for this analysis is defined as the 5-month period from May to September; however, to estimate certain crop yield benefits the modeling results were extended (as discussed in Chapter 11) to include months outside the 5-month ozone season.

[3] Based on AIRS, there were 949 ozone monitors with sufficient data, i.e., at least 9 hourly observations per day (8 am to 8 pm) in a given season.

required for every CAPMS grid-cell. Given available ozone monitoring data, we generated full-season ozone profiles for each location in the contiguous 48 states in two steps: (1) we combine monitored observations and modeled ozone predictions to interpolate hourly ozone concentrations to a grid of eight km by eight km population grid-cells, and (2) we converted these full-season hourly ozone profiles to an ozone measure of interest, such as the daily average [4,5] For the analysis of ozone impacts on agriculture, we use a similar approach except air quality is interpolated to county centroids as opposed to population grid-cells. Each approach is fully detailed in Abt Associates (1999).

10.4.4 Ozone Air Quality Results

A summary of the ozone air quality profiles used to assess the benefits of the final Section 126 rule will be presented in a supplemental volume to this RIA.

10.5 PM Air Quality Estimates

EPA used the emissions estimates described in Chapter 9 with a national-scale S-R Matrix based on CRDM to evaluate the effects of the final Section 126 rule on ambient concentrations of both PM_{10} and $PM_{2.5}$. Ambient concentrations of PM are composed of directly emitted particles and of secondary aerosols of sulfate, nitrate, ammonium, and organics. Relative to more sophisticated and resource-intensive three-dimensional modeling approaches, the S-R Matrix does not fully account for all the complex chemical interactions that take place in the atmosphere in the secondary formation of PM.

The S-R Matrix consists of fixed-coefficients that reflect the relationship between annual average PM concentration values at a single receptor in each county (i.e., a hypothetical monitor sited at the county population centroid) and the contribution by PM species to this concentration from each emission source (E.H. Pechan, 1996). The modeled receptors include all U.S. county centroids as well as receptors in 10 Canadian provinces and 29 Mexican cities/states. The methodology used in this RIA for estimating PM air quality concentrations is detailed in Pechan-Avanti (1999) and is similar to the method used in the July 1997 PM and Ozone NAAQS RIA (U.S. EPA, 1997a) and the RIA for the final Regional Haze Rule (U.S. EPA, 1999). The following sections summarize the development of the S-R Matrix and the steps taken to apply the S-R Matrix in this analysis to derive changes in PM air quality.

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[4]The 8 km grid squares contain the population data used in the health benefits analysis model, CAPMS. See Section C of this chapter for a discussion of this model.

[5]This approach is a generalization of planar interpolation that is technically referred to as enhanced Voronoi Neighbor Averaging (VNA) spatial interpolation (See Abt Associates (1999) for a more detailed description).

10.5.1 Development of the S-R Matrix

The S-R Matrix was developed using the CRDM, which uses assumptions similar to the Industrial Source Complex Short Term model (ISCST3), an EPA-recommended short range Gaussian dispersion model. The CRDM incorporates terms for wet and dry deposition and chemical conversion of SO_2 and NO_x to PM, and uses climatological summaries (annual average mixing heights and joint frequency distributions of wind speed and direction) from 100 upper air meteorological sites throughout North America. Meteorological data for 1990 coupled with emissions data from version 2.0 of the 1990 National Particulate Inventory (NPI) were used with CRDM to develop the S-R Matrix.

The NPI was separated into 5,944 sources (i.e., industrial point, utility, area, nonroad, and motor vehicle) of primary and precursor emissions. Each individual unit in the inventory was associated with one of four modeled source types (i.e., area, point sources with effective stack height of 0 to 250 m or 250 m to 500 m, and individual point sources with effective stack height above 500 m) for each county. Emissions that were modeled include SO_2, NO_x, and ammonia, which are needed to calculate ammonium sulfate and ammonium nitrate concentrations; VOC, which are needed to calculate secondary organic aerosols; and directly emitted PM_{10} and $PM_{2.5}$. Both anthropogenic and natural sources of each species were included.

The resulting transfer coefficients are adjusted to account for the chemical balance between sulfate, nitric acid, and ammonia (Latimer, 1996). The coefficients for SO_2, NO_x, and ammonia were multiplied by the ratios of the molecular weights of sulfate/SO_2, nitrate/nitrogen dioxide and ammonium/ammonia to obtain concentrations of sulfate, nitrate and ammonium.[6] In the presence of sulfate and nitric acid (the gas phase oxidation product of NO_x), ammonia reacts preferentially with sulfate to form particulate ammonium sulfate rather than react with nitric acid to form particulate ammonium nitrate. So, ammonium nitrate forms under conditions of excess ammonium, and only under relatively low temperatures. Accordingly, for each county receptor, the sulfate-nitrate-ammonium equilibrium is estimated based on the following simplifying assumptions:

1. All sulfate is neutralized by ammonium;
2. Ammonium nitrate forms only when there is excess ammonium;
2. Annual average particle nitrate concentrations are divided by four assuming that sufficiently low temperatures are present only one-quarter of the year.

The total particle mass of ammonium sulfate and ammonium nitrate is calculated by multiplying the anion concentrations of sulfate and nitrate by 1.375 and 1.290 respectively.

[6] Ratio of molecular weights: Sulfate/SO_2= 1.50; nitrate/nitrogen dioxide = 1.35; ammonium/ammonia = 1.06.

10.5.2 Fugitive Dust Adjustment Factor

As demonstrated in U.S. EPA (1998d), the 1990 CRDM predictions for fugitive dust are not consistent with measured ambient data. The CRDM-predicted average fugitive dust contribution to total $PM_{2.5}$ mass is 31 percent in the East and 32 percent in the West; however, monitoring data from the IMPROVE network show that minerals (i.e., crustal material) comprise only about five percent of $PM_{2.5}$ mass in the East and roughly 15 percent of $PM_{2.5}$ mass in the West (U.S. EPA, 1996b). These disparate results suggest a systematic overestimate in the fugitive dust contribution to total PM. This overestimate is further complicated by the recognition that the 1990 NPI significantly overestimates fugitive dust emissions. A comparison with the more recent National Emissions Trends inventory indicates that the NPI overestimates fugitive dust PM_{10} and $PM_{2.5}$ emissions by 40 percent and 73 percent respectively[7] (U.S. EPA, 1997c).

To address this bias, we applied a multiplicative factor of 0.25 across the modeling domain to fugitive dust emissions as a reasonable first-order attempt to reconcile differences between modeled predictions of PM_{10} and $PM_{2.5}$ and actual ambient data. This adjustment results in a fugitive dust contribution to modeled ambient $PM_{2.5}$ concentrations of 10 percent to 17 percent.[8] Even after this adjustment the fugitive dust fraction of total eastern $PM_{2.5}$ mass is 10.4 percent, which is still greater than the five percent indicated by IMPROVE monitors. However, given that the adjustment factor brings the modeled fugitive dust contribution to $PM_{2.5}$ mass more within the range of values reported from monitoring data, we adjusted the fugitive dust contribution to total PM that is estimated by the S-R Matrix by this factor. This factor still may result in an overprediction of the fugitive dust contribution in some locations.

10.5.3 Normalizing S-R Matrix Results to Observed Data

In an attempt to further ensure comparability between S-R Matrix results and measured annual average PM values, we also calibrated these results to observed monitoring data using factors developed for the PM and Ozone NAAQS RIA (U.S. EPA, 1997a). For the NAAQS RIA, a "calibration factor" was developed for each monitored county based on monitoring data from 1993 to 1995 for PM_{10} from the AIRS database.[9] This calibration procedure was applied to

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[7] Natural and man-made fugitive dust emissions account for 86 percent of PM_{10} emissions and 59 percent of $PM_{2.5}$ emissions in the 1997 version of the National Emission Trends Inventory.

[8] Using 0.25 multiplicative factor, fugitive dust as percentage of $PM_{2.5}$ mass for: Central U.S. = 17.2 percent; Eastern U.S.= 10.4 percent; Western U.S.= 10.6 percent. By comparison, without using a multiplicative factor, fugitive dust as a percentage of $PM_{2.5}$ mass for: Central U.S. = 44.6 percent; Eastern U.S. = 30.9 percent; Western U.S. = 31.5 percent.

[9] The normalization procedure was conducted for county-level modeled PM_{10} and $PM_{2.5}$ estimates falling into one of four air quality data tiers. The tiering scheme reflects increasing relaxation of data completeness

all S-R Matrix predictions, regardless of overprediction or underprediction relative to monitored values, and equally across all particle species contributing to the annual average PM value at a county-level receptor. The PM_{10} data represent the annual average of design value monitors averaged over three years (U.S. EPA, 1997f). We eliminated the standardization for temperature and pressure from this concentration data based upon proposed revisions to the reference method for PM_{10}.[10]

Because there is little $PM_{2.5}$ monitoring data available, we developed a general linear model to predict $PM_{2.5}$ concentrations directly from the monitored PM_{10} values (U.S. EPA, 1996b). The analysis used a SAS™ general linear model (i.e., GLM) procedure to predict $PM_{2.5}$ values as a function of season, region, and measured PM_{10} value. We then used these derived $PM_{2.5}$ data to calibrate the S-R Matrix model predictions of annual average $PM_{2.5}$.

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criteria and therefore increasing uncertainty for the annual design value (U.S. EPA, 1997f). Nationwide, Tier 1 monitored counties cover the 504 counties with at least 50 percent data completeness and therefore have the highest level of certainty associated with the annual design value. Tier 2 monitored counties cover 100 additional counties with at least one data point (i.e., one 24-hour value) for each of the three years during the period 1993 - 1995. Tier 3 monitored counties cover 107 additional counties with missing monitoring data for one or two of the three years 1993 - 1995. In total, Tiers 1, 2 and 3 cover 711 counties currently monitored for PM_{10} in the 48 contiguous states. In 1997 the PM_{10} monitoring network consisted of approximately 1600 individual monitors with a coverage of approximately 711 counties in the 48 contiguous states. Tier 4 covers the remaining 2369 non-monitored counties.

[10] See Appendix J - Reference Method for PM_{10} , Final Rule for National Ambient Air Quality Standards for Particulate Matter (Federal Register, Vol. 62, No. 138, p. 41, July 18, 1997).

10.5.4 PM Air Quality Results

This analysis employs emissions data for only those counties located in the 37 OTAG states as well as the District of Columbia. Air quality estimation is not restricted to the smaller final Section 126 region because the final Section 126 alternative may result in shifts in power generation, and hence shifts in emissions, anong utility sources located inside and outside the final Section 126 region. The broad 37 State area modeled for air quality purposes more clearly captures the effects of any modeled shifts in power generation. All emissions inputs to this modeling exercise were developed using information accurate as of September, 1999.

Because nationwide emissions are not used, the S-R Matrix results are incomplete for air quality predictions in the counties located in states along the western border of the OTAG domain. As shown in Figure 10-2, EPA has chosen not to include the air quality results from the six "buffer" states in the benefits analyses that are performed using the S-R Matrix results. Since the 31 remaining states are generally located more than 525 km (approximately 330 miles) from the states for which emissions information is not available, the air quality results for the 31 states is believed to be more reliable.

Table 10-4 provides a summary of the predicted ambient PM_{10} and $PM_{2.5}$ concentrations from the S-R Matrix for the 2007 base case and changes associated with final Section 126 rule. For the "Representative" scenario, the average annual mean concentrations of PM_{10} across all U.S. counties in the modeling domain declines by a negligible amount of 0.02 $\mu g/m^3$. The same relative decline is predicted for the population-weighted average for mean PM_{10}, which indicates rather uniform reductions in these concentrations across urban and rural areas. The impact of this rule on $PM_{2.5}$ concentrations are similarly small with average annual mean concentrations of $PM_{2.5}$ declining by 0.03 $\mu g/m^3$. Similar to PM_{10} concentrations, the population-weighted average does not differ much from the spatial average.

Table 10-5 provides additional insights on the changes in PM air quality resulting from the final Section 126 rule. This table focuses on the absolute and relative changes observed across individual U.S. counties. For the "Representative" scenario, the absolute change in mean PM_{10} concentration ranged from a slight increase of 0.09 $\mu g/m^3$ to a reduction of 0.24 $\mu g/m^3$, while the relative change ranged from an increase of 0.5 percent to a reduction of 0.9 percent. Alternatively, for mean $PM_{2.5}$, the absolute change ranged from an increase of 0.05 $\mu g/m^3$ to a reduction of 0.25 $\mu g/m^3$, while the relative change ranged from an increase of 0.4 percent to a reduction of 1.7 percent.

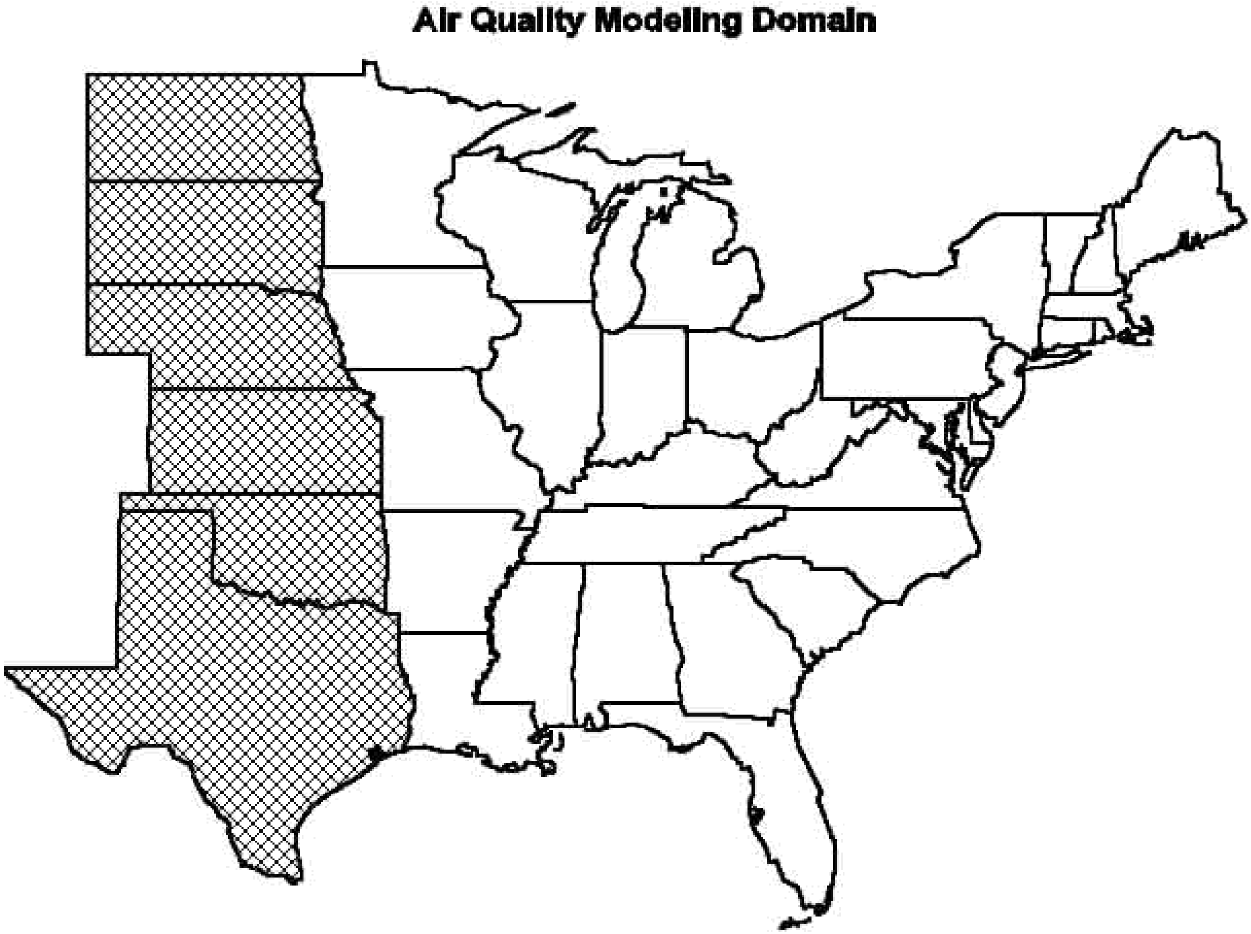

Figure 10-2. S-R Matrix Air Quality Modeling Domain

*Buffer states are shaded--emissions are included for these states, but air quality concentrations are not calculated for these states.

Table 10-4. Summary of 2007 Base Case PM Air Quality and Changes Due to Final Section 126 Rule

Statistic	*2007 Base Case*	*"SO2 Increasing" Scenario*		*"Representative" Scenario*		*"SO2 Decreasing" Scenario*	
		Change[a]	*Percent Change*	*Change[a]*	*Percent Change*	*Change[a]*	*Percent Change*
PM_{10}							
Minimum Annual Mean PM_{10} ($\mu g/m^3$)[b]	5.78	0.01	0.2%	0.01	0.2%	0.00	0.0%
Maximum Annual Mean PM_{10} ($\mu g/m^3$)[b]	137.21	0.05	0.0%	0.00	0.0%	-0.08	-0.1%
Average Annual Mean PM_{10} ($\mu g/m^3$)	23.00	-0.00	0.0%	-0.02	-0.1%	-0.03	-0.1%
Median Annual Mean PM_{10} ($\mu g/m^3$)	22.79	-0.01	0.0%	-0.03	-0.1%	-0.02	-0.1%
Population-Weighted Avg Annual Mean PM_{10} ($\mu g/m^3$)[c]	28.10	-0.01	0.0%	-0.03	-0.1%	-0.04	-0.2%
$PM_{2.5}$							
Minimum Annual Mean $PM_{2.5}$ ($\mu g/m^3$)[b]	3.68	0.00	0.0%	0.00	0.0%	0.00	0.0%
Maximum Annual Mean $PM_{2.5}$ ($\mu g/m^3$)[b]	83.29	0.06	0.1%	0.01	0.0%	-0.08	-0.1%
Average Annual Mean $PM_{2.5}$ ($\mu g/m^3$)	11.29	-0.00	0.0%	-0.02	-0.2%	-0.03	-0.3%
Median Annual Mean PM_{10} ($\mu g/m^3$)	11.36	-0.02	-0.1%	-0.03	-0.3%	-0.02	-0.5%
Population-Weighted Avg Annual Mean $PM_{2.5}$ ($\mu g/m^3$)[c]	13.40	-0.01	-0.1%	-0.03	-0.2%	-0.04	-0.3%

[a] The change is defined as the control case value minus the base case value.
[b] The base case minimum (maximum) is the value for the county with the lowest (highest) annual average. The change relative to the base case is the observed change for the county with the lowest (highest) annual average in the base case.
[c] Calculated by summing the product of the projected 2007 county population and the estimated 2007 county PM concentration, and then dividing by the total population in the modeling domain.

Table 10-5. Summary of Absolute and Relative Changes in PM Air Quality Due to Final Section 126 Rule

Statistic	*"SO2 Increasing" Scenario*		*"Representative" Scenario*		*"SO2 Increasing" Scenario*	
	Absolute Change from 2007 Base Case ($\mu g/m^3$) [a]	*Relative Change from 2007 Base Case (%)* [b]	*Absolute Change from 2007 Base Case ($\mu g/m^3$)* [a]	*Relative Change from 2007 Base Case (%)* [b]	*Absolute Change from 2007 Base Case ($\mu g/m^3$)* [a]	*Relative Change from 2007 Base Case (%)* [b]
PM_{10}						
Minimum	0.21	0.92%	0.09	0.46%	0.27	0.95%
Maximum	-1.74	-4.27%	0.24	-0.86%	-0.99	-2.35%
Average	-0.003	-0.01%	-0.021	-0.09%	-0.033	-0.13%
Median	-0.000	0.00%	-0.010	-0.06%	-0.020	-0.08%
Population-Weighted Average[c]	-0.010	-0.02%	-0.025	-0.08%	-0.041	-0.14%
$PM_{2.5}$						
Minimum	0.20	1.52%	0.05	0.44%	0.26	1.60%
Maximum	-1.70	-5.69%	0.25	-1.69%	-0.98	-3.13%
Average	-0.003	0.00%	-0.020	-0.18%	-0.033	-0.25%
Median	0.010	0.07%	-0.010	-0.10%	-0.020	-0.17%
[c] Population-Weighted Average	-0.009	-0.04%	-0.025	-0.17%	-0.040	-0.27%

[a] The absolute change is defined as the control case value minus the base case value for each county.
[b] The relative change is defined as the absolute change divided by the base case value, or the percentage change, for each county.
[c] Calculated by summing the product of the projected 2007 county population and the estimated 2007 county PM absolute/relative measure of change, and then dividing by the total population in the modeling domain.

10.6 Nitrogen Deposition Estimates

This section presents the methods and results of estimating the potential reductions in airborne nitrogen deposition loadings to estuaries associated with the final Section 126 Rule. A sampling of 12 estuaries (10 East Coast and 2 Gulf Coast estuaries) were used for this analysis because of the availability of necessary data and their potential representativeness. For each estuary, we completed the following steps as part of this analysis:

1. Baseline loadings of atmospherically supplied nitrogen were obtained from data provided in Valigura et al (1996) and from local offices of the Chesapeake Bay Program and the National Estuary Program,

2. Deposition from atmospheric emissions were divided into local and regional areas that contribute to airborne nitrogen deposition,

3. Deposition coefficients, which relate NOx emission changes from a source region to nitrogen deposition changes at a receptor region, were derived for local and regional contributors, and

4. Changes in nitrogen deposition loadings were estimated by multiplying NOx emission changes for the local and regional contributing areas by the appropriate deposition coefficients.

For five of the 12 estuaries, estimates of both direct deposition to the tidal waters and indirect deposition to the entire watershed were available from the literature. For the remaining seven estuaries, only the direct deposition estimates were available. Therefore, to obtain indirect deposition estimates where missing, we used RADM-derived nitrogen flux for the watershed (Dennis, 1997). This analysis assumes that 10 percent of nitrogen deposited onto the watershed is deliver via export (pass-through) to the estuary.[11] The calculated indirect deposition value is added to the direct deposition value obtained from the literature to arrive at the total load from atmospheric deposition.

As shown in Step 4 above, the nitrogen deposition results are heavily dependent upon the deposition coefficients that estimate the impact of NOx emission changes on nitrogen deposition loadings. For this analysis, two deposition coefficients, an *alpha* and a *beta*, were developed for each estuary. The alpha coefficient relates local emissions to deposition and the beta coefficient relates regional emissions to deposition. These coefficients are calculated for each estuary using deposition outputs from RADM as employed for the final Regional NOx SIP Call (EPA, 1998d). More detail on this approach and results may be found in Pechan-Avanti Group (1999).

Table 10-6 provides a summary of the baseline deposition and change in nitrogen deposition estimates for the selected estuaries as a result of the Section 126 rule. Because SO2 emissions are not a determinant of nitrogen deposition, the results will not vary across SO2 banking scenarios so that a single set of results are presented. As shown, implementation of this rule results in a 8.2 percent reduction in the average annual deposition across these estuaries. These predicted reductions range from a low of 3.2 percent for Tampa Bay to a high of 11.4 percent for Delaware Inland Bays.

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[11] This assumption is consistent with reported case studies such as Valiela et al, 1997. These authors report that 89% of atmospherically deposited nitrogen was retained by the watershed of Waquoit Bay, suggesting an 11% pass through factor.

Table 10-6. Summary of 2007 Nitrogen Deposition in Selected Estuaries and Changes Due to Final Section 126 Rule (million kg/year)

		Section 126 Rule	
Estuary	*2007 Base Case*	*Change*[a]	*Percent Change*
Albemarle/Pamlico Sound	14.71	-1.49	10.1%
Cape Cod Bay	4.91	-0.35	7.2%
Chesapeake Bay	22.87	-2.10	9.2%
Delaware Bay	4.20	-0.32	7.5%
Delaware Inland Bays	0.56	-0.06	11.4%
Gardiners Bay	1.53	-0.11	7.4%
Hudson River/Raritan Bay	4.78	-0.30	6.3%
Long Island Sound	6.90	-0.41	5.9%
Massachusetts Bay	1.64	-0.12	7.1%
Narragansett Bay	1.45	-0.10	7.0%
Sarasota Bay	0.46	-0.02	3.9%
Tampa Bay	2.92	-0.09	3.2%
All Selected Estuaries	66.93	-5.47	8.2%

[a] Change is defined here as the emissions level after implementing the 126 Rule minus the base case emissions.

10.7 Visibility Degradation Estimates

Visibility degradation is often directly proportional to decreases in light transmittal in the atmosphere. Scattering and absorption by both gases and particles decrease light transmittance. To quantify changes in visibility, our analysis computes a light-extinction coefficient, based on the work of Sisler (1996), which shows the total fraction of light that is decreased per unit distance. This coefficient accounts for the scattering and absorption of light by both particles and gases, and accounts for the higher extinction efficiency of fine particles compared to coarse particles. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon (soot), and soil (Sisler, 1996).

Based upon the light-extinction coefficient, we also calculated a unitless visibility index, called a "deciview," which is used in the valuation of visibility. The deciview metric provides a linear scale for perceived visual changes over the entire range of conditions, from clear to hazy. Under many scenic conditions, the average person can generally perceive a change of one deciview. Because the visibility benefits analysis distinguishes between general regional visibility degradation and that particular to Federally-designated Class I areas (i.e., national parks, forests, recreation areas, wilderness areas, etc.), we separated estimates of visibility degradation into "residential" and "recreational" categories. The estimates of visibility degradation for the "recreational" category apply to Federally-designated Class I areas, while estimates for the "residential" category apply to non-Class I areas. Deciview estimates are developed from the estimated county-level changes in particulate matter generated from results of the S-R Matrix for the 2007 base case and the 2007 policy scenarios for the final Section 126 rule. These deciview estimates are then aggregated to one of eight regions in the case of the residential category (as defined by the underlying study) and one of six regions in the case of the recreational category (as defined by Class I Visibility Regions described in Chapter 11). More detail on this approach and results may be found in Pechan-Avanti Group (1999).

Table 10-7 provides a summary of the visibility degradation estimates in terms of deciviews by residential category across U.S. regions. As shown under the "Representative" scenario, for the regions covered under this rule, there is not a perceptable change in residential visibility, i.e., percentage change roughly equal to zero. All predicted changes in visibility are very small with only the Southeast and South Central regions showing the largest improvement. In addition, Table 10-8 provides a summary of the visibility degradation estimates in terms of deciviews for Class I areas (i.e., recreational category) in the Southeast and Northeast/Midwest visibility regions. As observed for residential visibility, there is only a slightly perceptable improvement in both of the recreational visibility regions included in this analysis.

Table 10-7. Summary of 2007 Visibility Degradation Estimates by Region: Residential (Annual Average Deciviews)

Study Regions	2007 Base Case	"SO2 Increasing" Scenario		"Representative" Scenario		"SO2 Decreasing" Scenario	
		Change[a]	*Percent Change*	*Change*[a]	*Percent Change*	*Change*[a]	*Percent Change*
Southeast	23.29	-0.01	0.0%	-0.03	-0.1%	-0.05	-0.2%
Northeast	24.04	0.02	0.1%	0.00	0.0%	-0.06	-0.2%
North Central	21.43	0.01	0.0%	-0.02	0.1%	-0.01	-0.1%
South Central	22.94	0.00	0.0%	-0.03	-0.1%	-0.01	0.0%
National	22.66	0.01	0.0%	-0.02	-0.1%	-0.03	-0.1%

[a] The change is defined as the control case deciview level minus the base case deciview level.

Table 10-8. Summary of 2007 Visibility Degradation Estimates by Region: Recreational (Annual Average Deciviews)

Class I Visibility Regions	2007 Base Case	"SO2 Increasing" Scenario		"Representative" Scenario		"SO2 Decreasing" Scenario	
		Change[a]	*Percent Change*	*Change*[a]	*Percent Change*	*Change*[a]	*Percent Change*
Southeast	22.58	0.02	0.1%	-0.02	-0.1%	-0.03	-0.1%
Northeast/Midwest	21.44	0.02	0.1%	-0.01	0.0%	-0.02	-0.1%
National	22.10	0.02	0.1%	-0.01	-0.1%	-0.03	-0.1%

[a] The change is defined as the control case deciview level minus the base case deciview level.

10.8 Uncertainty in Air Quality Modeling

There is uncertainty associated with the air quality analyses used to predict ozone, PM, nitrogen deposition, and visibility changes due to the Section 126 rule. These uncertainties arise not only from the model approach and parameters employed to characterize air quality in the baseline and control scenarios but also from the large number of input variables such as emissions inventories and meteorology. The uncertainties related to the input variables are compounded by the need to project data for a future year, as is the case in this analysis with 2007. Although these uncertainties apply to each component of air quality discussed here, the remainder of this section focuses on the modeling and results for particulates. The uncertainties and biases in the 1990 modeled predictions combined with uncertainties in 2007 emission projections bring about similar uncertainties and biases in the 2007 visibility improvement predictions. Table 10-9 lists these potential uncertainties and biases.

Although the CRDM S-R matrix serves as a useful tool in the design of cost-effective PM control strategies, the modeling approach does not reflect application of state-of-the-art techniques. Many of the physical and chemical formulations in the CRDM are crude representations of actual mixing and reaction phenomena required to address aerosol formation, transport and removal phenomena. Where available, more scientifically credible RADM results were used to complement the CRDM results, e.g., with regard to nitrogen deposition. However, even with the anticipated delivery of more comprehensive modeling techniques, the scarcity of speciated ambient data in both urban and rural environments to evaluate model behavior will continue to compromise the certainty of model-derived conclusions.

In generating the matrix of S-R transfer coefficients, CRDM employs a large number of input variables in its calculations, including meteorological data (i.e., wind speed, wind velocity, and stability conditions). While there have been no studies of uncertainty associated with CRDM output, Freeman *et al.* (1986) used error propagation and Monte Carlo simulation to study the uncertainty of short range concentration estimates calculated by a similar model, EPA's ISCST Gaussian dispersion model for a single point source. Freeman *et al.* found that for relatively low values of uncertainty assigned to input values (1 to 10 percent), the uncertainty of the concentration at distances from 3 to 15 kilometers downwind of a source averaged 16 percent. When input data uncertainties were increased by a factor of 4; however, the output uncertainty ranged from about 75 to 160 percent.

Despite application of the fugitive dust adjustment factor, comparisons of modeled PM predictions to ambient data indicate that the CRDM overpredicts the contribution of fugitive dust to total $PM_{2.5}$ mass and, therefore, to visibility impairment. The CRDM may overestimate or underestimate other fine particle species when evaluating county-level model predictions relative to $PM_{2.5}$ ambient data. For example, in some PM residual nonattainment counties, the predicted biogenic organic contribution to $PM_{2.5}$ mass appears to be overestimated relative to speciated monitoring data. However, at the national level, there appears to be no systematic bias to the modeled air quality predictions for the non-fugitive dust particle species.

Because 1990 emissions are an input to the CRDM model, the uncertainties associated with the emissions inventory are carried through to the air quality modeling. As discussed in Section 10.4, apart from the fugitive dust and biogenic VOC and SOA categories, emissions of primary PM and PM precursors are uncertain although with no known bias. Fugitive dust PM emissions appear to be overestimated by 40 percent for PM_{10} and 73 percent for $PM_{2.5}$ relative to the more recent NET Inventory, while the biogenic VOC emissions are underestimated relative to the more recent BEIS2 estimates. Finally, the methodology used to estimate SOA formation from reactive VOCs may overestimate SOA emissions and, thus, ambient concentrations of SOA.

In addition, there is uncertainty associated with the 1993 - 1995 monitored annual average and 24-hour PM_{10} concentration values that are used to calibrate the ambient concentrations generated by the CRDM S-R Matrix at the county-level receptors. These monitoring values are taken from the AIRS data base, which has a performance requirement of 5 µg/m^3 for concentrations less than 80 µg/m^3 and $\pm$ 7 percent for concentrations greater than 80 µg/m^3. However, a comparison of AIRS data obtained from side-by-side samplers of the same and different types indicated measurement differences ranging from 10 to 14 percent for like samplers to 16 to 26 percent for dissimilar samplers (U.S. EPA, 1996k). However, there is no known bias associated with these values.

Since the $PM_{2.5}$ data are derived from monitored PM_{10} concentrations, they too have associated uncertainty due to instrument measurement error. Additionally, and more importantly, the $PM_{2.5}$ values are predicted from a regression model (U.S. EPA, 1996e), and therefore are subject to uncertainty associated with this model. Subsequent reanalysis of the model has shown that there is no systematic bias to the $PM_{2.5}$ estimates (U.S. EPA, 1997d).

Table 10-9. Uncertainties and Possible Biases in PM Air Quality Methods and Results

Potential Source of Uncertainty	Positive Bias? (Overestimate)	Negative Bias? (Underestimate)	Bias Unclear
Base Year 1990			
- 1990 emissions	✓ (fugitive dust, SOA)	✓(total biogenic VOC and SOA)	✓ (other emissions)
- 1993 - 1995 PM10 ambient data			✓
- 1993 - 1995 PM2.5 derived data			✓
- CRDM 1990 adjusted S-R matrix	✓ (fugitive dust)		✓ (other emissions)
Projection Year 2007			
- Uncertainties from 1990 adjusted S-R matrix	✓ (fugitive dust)		✓
- 2007 emissions projections	✓ (fugitive dust, SOA)	✓ (total biogenic VOC and SOA)	✓ (other emissions)
- 2007 air quality predictions	✓ (fugitive dust)		✓ (other particle species)

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Chapter 11. Benefits of Regional NOx Reductions

11.1 Results in Brief

This chapter provides benefits results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The benefits results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the findings based on the 8-hour ozone NAAQS**.**

Physical effects and monetary benefits are calculated for the selected Section 126 regulatory alternative (0.15 trading). Incremental benefits (in 1997$) from implementation of the Section 126 NOx controls for the 2007 "Representative Year" SO_2 emissions banking scenario (holding sulfates constant between baseline and control air quality levels) are expected to be $1.2 billion. These estimates represent only the value of quantified health and welfare effects associated with changes in particulate matter (PM). We were unable to provide quantified or monetized benefit estimates for health and welfare effects associated with ambient concentrations of ozone based on actual air quality modeling of ozone changes by the signature date for this rulemaking. Instead, to provide a more representative benefits estimate for comparison with costs in Chapter 12, we use a benefit transfer method to develop a projected estimate of ozone-related benefits for the final Section 126 rule. A description of the benefit transfer method and the projected estimate of ozone-related benefits is presented in Chapter 12. Estimates of ozone-related health and welfare benefits based on modeled air quality changes will be available in January 2000 in a supplementary volume to this RIA**.**

The largest monetized benefit is associated with reductions in premature mortality associated with PM exposure. Other significant effects include reductions in chronic bronchitis and improvements in visibility at national parks and wilderness areas. The final Section 126 rule also results in significant reductions in deposition of nitrogen to sensitive Eastern estuaries that will help regional agencies reach nitrogen loading reduction targets.

This benefits analysis does not quantify all potential benefits or disbenefits. The magnitude of the unquantified benefits associated with omitted categories, such as damage to ecosystems or damage to industrial equipment and national monuments, is not known. However, to the extent that unquantified benefits exceed unquantified disbenefits, the estimated benefits presented above will be an underestimate of actual benefits. The methods for estimating monetized benefits for the final Section 126 rule and a more detailed analysis of the results are presented below.

11.2 Introduction

This chapter reports EPA's analysis of the economic benefits of the final Section 126 rule. EPA is required by Executive Order 12866 to estimate the benefits of new pollution control regulations. The analysis presented here attempts to answer two questions: 1) what are the physical effects of changes in ambient air quality resulting from reduction in NOx emissions?; and 2) how much are the changes in air quality worth to U.S. citizens as a whole in monetary terms? It constitutes one part of EPA's thorough examination of all aspects of the relative merits of regulatory alternatives.

This chapter provides benefits results associated with Federally-imposed requirements in the May 25, 1999 Notice of Final Rulemaking (NFR) to reduce NOx emissions from sources contributing to downwind nonattainment of the ozone national ambient air quality standard (NAAQS). The benefits results presented in this chapter take into account the changes in the NOx emissions inventory made as a result of the inventory correction notices issued on January 13, 1999 and May 14, 1999, as well as the narrowed geographic scope and sources affected by the Section 126 remedy as a result of EPA's stay of the findings based on the 8-hour ozone NAAQS.

The changes in emissions resulting from the implementation of Section 126 controls have been described in Chapter 9. These changes in turn are expected to bring about different levels of ambient concentrations over time and space, which have been modeled and are described in Chapter 10. Changes in ambient concentrations will lead to new levels of environmental quality in the US, reflected both in human health and in non-health welfare effects. The final Section 126 rule is expected to result in significant NOx reductions in the Eastern U.S. However, due to the NOx trading program, some localized increases in SO_2 emissions relative to expected levels without the rule are predicted to occur in 2007, our selected analytical year. These increases occur because the banking provisions in the Title IV Acid Rain permit program which caps total emissions of SO_2 allow SO_2 emissions to vary over time with higher emissions in some years being offset by lower emissions in other years. Our benefits analysis is designed to take into account both decreases and increases in emissions that result from a rule. However, given the anomalous nature of the SO_2 emissions increase in 2007 (SO_2 emissions decrease in every other year), we construct alternative scenarios to provide a more representative analysis of the final Section 126 rule.

Three alternative scenarios for expected emissions of SO_2 are presented. As explained in more detail in Chapter 9, selection of 2007 as the analytical year for the benefits analysis resulted in a SO_2 emissions and air quality results that are not representative of the expected change in air quality for most years when the rule is in effect. The first scenario constructs a proxy for a "representative year" (in terms of SO_2 emissions) by zeroing out all changes in sulfates, both positive and negative, in calculating the changes in $PM_{2.5}$. Changes in $PM_{2.5}$ are then driven solely by changes in nitrate concentrations. The second scenario presents the 2007 results "as is", characterized by a high level of SO_2 permit withdrawals and accompanying SO_2 emission increases (which leads to increases in sulfate particles in some areas). The third scenario presents an analysis based on a year (2004) in which SO_2 permits are banked and SO_2 emissions decrease. A full set of results is presented for each scenario, however, EPA believes that the "representative year" scenario is a closer approximation to the expected annual benefits of the final Section 126 rule, and will thus be the only scenario that is carried over into the comparison of benefits and costs.

EPA has used the best available information and tools of analysis to quantify the expected changes in public health and the environment and to monetize the economic benefits of the final Section 126 rule, given the constraints on time and resources available for the analysis. We have attempted to be as clear as possible in presenting our assumptions, sources of data, and sources of potential uncertainty in the analysis. We urge the reader to pay particular attention to the fact that not all the benefits of the rule can be estimated with sufficient reliability to be quantified and valued in monetary terms. The omission of these items from the total of monetary benefits reflects our inability to measure them. It does not indicate their lack of importance in the consideration of the benefits of this rulemaking. When it is possible to qualitatively characterize a benefits category, we provide a discussion, although the benefit is not included in the estimate of total benefits.

We were unable to provide quantified or monetized benefit estimates for health and welfare effects associated with ambient concentrations of ozone based on actual air quality modeling of ozone changes by the signature date for this rulemaking. Instead, to provide a more representative benefits estimate for comparison with costs in Chapter 12, we use a benefit transfer method to develop a projected estimate of ozone-related benefits for the final Section 126 rule. A description of the benefit transfer method and the projected estimate of ozone-related benefits is presented in Chapter 12. Estimates of ozone-related health and welfare benefits based on modeled air quality changes will be available in January 2000 in a supplementary volume to this RIA

EPA relies heavily on the advice of its Science Advisory Board in determining the health and welfare effects considered in the benefits analysis and in establishing the most scientifically valid measurement and valuation techniques. Since the publication of the Section 126 Proposal/Final NOx SIP Call RIA, we have updated the set of assumptions and methods used in our analysis to reflect SAB recommendations. The major changes include

- Ozone mortality is no longer included as a monetized health effect in the primary analysis.
- Chronic asthma has been added as an ozone-related health effect in the primary analysis.
- A threshold of zero (as opposed to 15 $\mu g/m^3$ or the lowest observed level in a study) is assumed for all particulate matter related health effects.
- A five year distributed lag in the incidence of premature mortality related to PM exposure is assumed to exist.

- Asthma-related emergency room visits have been added as an ozone and PM-related health effect in the primary analysis.
- Household soiling and residential visibility is no longer included as a monetized PM-related welfare effects in the primary analysis.
- The value of reductions in nitrogen deposition to estuaries is no longer included as a monetized welfare effect in the primary analysis.
- Agricultural benefits are estimated using the AGSIM© model, rather than the Regional Model Farm.

These changes reflect recommendations of the SAB made during the review of the §812 Prospective Report to Congress (U.S. EPA, 1999a). Exclusion of ozone mortality, household soiling, residential visibility, and estuarine benefits does not indicate that these effects are not important. Rather, it reflects gaps in our ability to adequately measure or value these effects.

This chapter proceeds as follows: Section 11.3 provides an overview of benefits estimation. Section 11.4 summarizes the way that emissions and air quality changes are used as inputs to our analysis. Section 11.5 introduces the kinds of benefits that are estimated and the techniques that are used. Section 11.6 provides a discussion of how we incorporate uncertainty into our analysis. We then proceed to report the results of the analysis of two broad benefit categories related to human health (11.7) and human welfare (11.8). Section 11.9 reports our estimates of total monetized benefits and alternative calculations. Finally, Section 11.10 provides a discussion highlighting the importance of the results in context.

11.3 Overview of Benefit Estimation

This section provides an overview of terms and issues in the analysis of benefits. The methods and information in this model build on similar analyses EPA has performed in recent years, including the §812 Prospective Report to Congress (EPA, 1999a), the PM and Ozone NAAQS RIA (EPA, 1997), and in the NOx SIP call, Regional Haze, and Proposed Tier 2 RIAs (EPA, 1998, 1999b, 1999c). We refer the reader to these studies, which received extensive peer review by other federal agencies and/or the EPA Science Advisory Board, for more detailed presentations.

We use the term benefits to refer to any and all positive effects of emissions changes on social welfare that we expect to result from the final rule. We use the term environmental costs (also commonly referred to as "disbenefits") to refer to any and all negative effects of emissions changes on social welfare that result from the final rule. Where it is possible to quantify benefits and environmental costs, our measures are those associated with economic surplus in accepted applications of welfare economics. These measures estimate (primarily through benefits transfer) the willingness of the affected population to pay for changes in environmental quality and associated health and welfare effects.

11.4 Linking Regulation to Environmental and Economic Consequences

This chapter presents the results of EPA's analysis of potential benefits. The emissions reductions that will result from the final Section 126 rule have of course not actually occurred yet. The changes in human health and welfare outcomes to which economic values are ascribed are predictions. These predictions are based on the best available scientific evidence and judgment, however there is unavoidable uncertainty associated with each step in the complex process between regulation and specific health and welfare outcomes. The ways in which we deal with these uncertainties are discussed in section 11.6.

Figure 11-1 illustrates the steps necessary to link the final Section 126 rule with economic measures of benefits. The first two steps involve the specification and implementation of the regulation. First, the need for reductions in interstate transport of NOx is established for states affected by the final rule. Next, a set of emissions controls which will meet the requirements for ozone reduction in a cost-efficient manner are selected (see Chapters 6 and 7).

The changes in pollutant emissions resulting from the hypothesized controls are then calculated. Emissions models for individual sources must predict what emissions of pollutants will actually be when sources adjust their operations in response to new regulations.

Next, the predicted emissions are used as inputs to air quality models that predict ambient concentrations of pollutants over time and space. These concentrations depend on climatic conditions and complex chemical interactions. We have used the best available air quality models to estimate the changes in ambient concentrations (from baseline levels) that are used as the basis for this benefits analysis (see Chapter 10).

The predicted changes in ambient air quality then serve as inputs into functions that predict changes in health and welfare outcomes. We use the term "endpoints" to refer to specific effects associated with changes in air quality. Table 11-1 lists the human health and welfare effects identified for ozone and PM. This list includes both those effects quantified (and/or monetized) in this analysis and those for which we are unable to provide quantified estimates. For changes in risks to human health from ozone and PM, quantified endpoints include changes in mortality and in a number of pollution-related non-fatal health effects. To estimate these endpoints, EPA combines changes in ambient air quality levels with clinical and epidemiological evidence about population health response to pollution exposure. For welfare effects, the endpoints are defined in terms of levels of physical damage (for materials damage), economic output (agriculture and forestry), light extinction (for visibility), and increases in terrestrial and estuarine nutrient loading (for ecological effects).

As with emissions and air quality estimates, EPA's estimates of the effect of ambient pollution levels on all of these endpoints represent the best science available to the Agency. The majority of the analytical assumptions used to develop our estimates have been reviewed and approved by the EPA Science Advisory Board. However, like all estimates, they contain unavoidable uncertainty, as does any prediction of the future. In section 11.6 and in the sections on health and welfare endpoints, this uncertainty is discussed and characterized.

Figure 11-1
Methodology for Section 126 Benefits Analysis

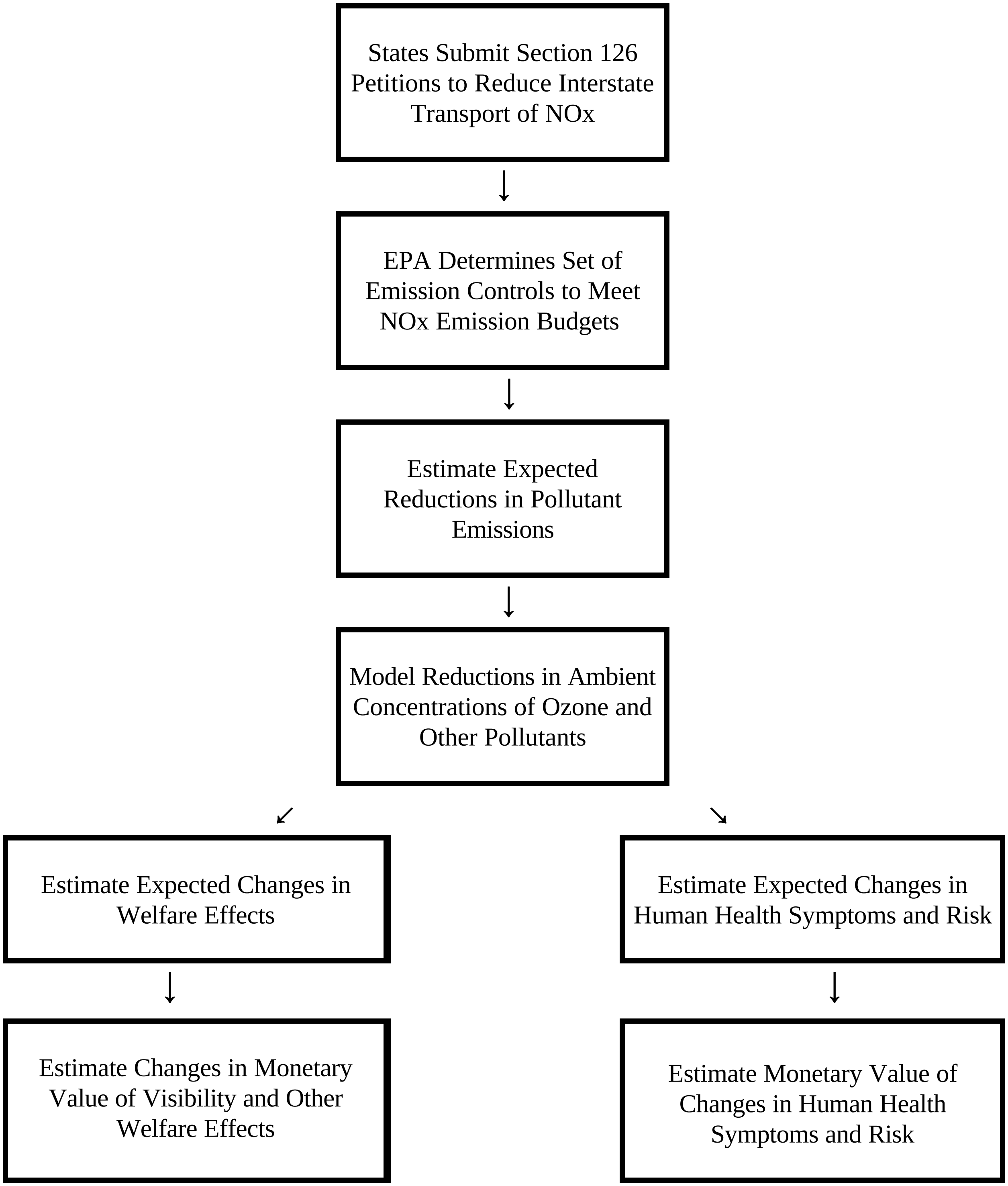

Table 11-1.
Human Health and Welfare Effects of Ozone and Particulate Matter

Pollutant	Primary Quantified and Monetized Effects	Alternative Quantified and/or Monetized Effects	Unquantified Effects
Ozone Health	Chronic asthma[a] Minor restricted activity days and acute respiratory symptoms Hospital admissions - respiratory and cardiovascular Emergency room visits for asthma		Premature mortality[b] Increased airway responsiveness to stimuli Inflammation in the lung Chronic respiratory damage Premature aging of the lungs Acute inflammation and respiratory cell damage Increased susceptibility to respiratory infection Non-asthma respiratory emergency room visits Reduction in screening of UV-b radiation
Ozone Welfare	Decreased worker productivity Decreased yields for commercial crops		Decreased yields for commercial forests Decreased yields for fruits and vegetables Decreased yields for non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Damage to ecosystem functions

Pollutant	Primary Quantified and Monetized Effects	Alternative Quantified and/or Monetized Effects	Unquantified Effects
PM Health	Premature mortality Bronchitis - chronic and acute Hospital admissions - respiratory and cardiovascular Emergency room visits for asthma Lower and upper respiratory illness Shortness of breath Minor restricted activity days and acute respiratory symptoms Work loss days		Infant mortality Low birth weight Changes in pulmonary function Chronic respiratory diseases other than chronic bronchitis Morphological changes Altered host defense mechanisms Cancer Non-asthma respiratory emergency room visits
PM Welfare	Visibility in Southeastern Class I areas	Visibility in Northeastern and Midwestern Class I areas Visibility in Eastern residential areas Household soiling	
Nitrogen and Sulfate Deposition Welfare		Costs of nitrogen controls to reduce eutrophication in selected eastern estuaries	Impacts of acidic sulfate and nitrate deposition on commercial forests Impacts of acidic deposition to commercial freshwater fishing Impacts of acidic deposition to recreation in terrestrial ecosystems Reduced existence values for currently healthy ecosystems Impacts of nitrogen deposition on commercial fishing, agriculture, and forests Impacts of nitrogen deposition on recreation in estuarine ecosystems

[a] While no causal mechanism has been identified linking new incidences of chronic asthma to ozone exposure, a recent epidemiological study shows a statistical association between long-term exposure to ozone and incidences of chronic asthma in some non-smoking men, but not in wormen.

[b] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope, et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.

11.5 Methods for Estimating Benefits from Air Quality Improvements

Environmental and health economists have a number of methods for estimating the economic value of improvements in (or deterioration of) environmental quality. The method used in any given situation depends on the nature of the effect and the kinds of data, time and resources that are available for investigation and analysis. This section provides an overview of the methods EPA selected to monetize the benefits included in the Section 126 RIA.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure economic benefits for individual rulemakings. As a result, our estimates are based on the best available methods of benefits transfer. Benefits transfer is the science and art of adapting primary benefits research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Where appropriate, adjustments are made for the level of environmental quality change, the sociodemographic and economic characteristics of the affected population, and other factors in order to improve the accuracy and robustness of benefits estimates.

In general, economists tend to view an individual's willingness-to-pay for an improvement in environmental quality as the appropriate measure of the value of a risk reduction. An individual's willingness-to-accept (WTA) compensation for not receiving the improvement is also a valid measure. However, WTP is generally considered to be a more readily available and conservative measure of benefits. Adoption of WTP as the measure of value implies that the value of environmental quality improvements is dependent on the individual preferences of the affected population and that the existing distribution of income (ability to pay) is appropriate.

For many goods, WTP can be observed by examining actual market transactions. For example, if a gallon of bottled drinking water sells for one dollar, it can be observed that at least some persons are willing to pay one dollar for such water. For goods not exchanged in the market, such as most environmental "goods," valuation is not as straightforward. Nevertheless, a value may be inferred from observed behavior, such as sales and prices of products that result in similar effects or risk reductions, (e.g., non-toxic cleaners or bike helmets). Alternatively, surveys may be used in an attempt to directly elicit WTP for an environmental improvement.

One distinction in environmental benefits estimation is between use values and non-use values. Although no general agreement exists among economists on a precise distinction between the two (see Freeman, 1993), the general nature of the difference is clear. Use values are those aspects of environmental quality that affect an individual's welfare more or less directly. These effects include changes in product prices, quality, and availability, changes in the quality of outdoor recreation and outdoor aesthetics, changes in health or life expectancy, and the costs of actions taken to avoid negative effects of environmental quality changes.

Non-use values are those for which an individual is willing to pay for reasons that do not relate to the direct use or enjoyment of any environmental benefit. Non-use values are most frequently divided into two categories: existence values and bequest values. Existence values refer to situations where individuals value (are willing to pay for) the knowledge of an improved environmental state (or avoidance of a deteriorating environmental state) . An example is the willingness to pay (WTP) for the preservation of the blue whale even when an individual has no plan to take a trip to observe the species nor to derive any direct benefit from its survival. Existence values commonly rise from philosophical, ethical, or religious attitudes about the rights of nature and the responsibilities of humans. The other commonly posited category of non-use benefits is bequest value. People are willing to devote resources to environmental preservation because of their perceived obligation or desire to leave higher states of environmental quality to future generations. Bequest values can also be thought of as arising from the philosophical, ethical, and religious beliefs of individuals.

Non-use values are not traded, directly or indirectly, in markets. For this reason, the measurement of non-use values has proved to be significantly more difficult than the measurement of use values. The air quality changes produced by the Section 126 rule cause changes in both use and non-use values, but the monetary benefit estimates are almost exclusively for use values.

More frequently than not, the economic benefits from environmental quality changes are not traded in markets, so direct measurement techniques can not be used. Avoided cost methods are ways to estimate the costs of pollution by using the expenditures made necessary by pollution damage. For example, if buildings must be cleaned or painted more frequently as levels of PM increase, then the appropriately calculated increment of these costs is a reasonable estimate of true economic benefits when PM levels are reduced. A variation on the avoided cost method is used to provide an alternative estimate of the benefits of reductions in nitrogen deposition to estuaries (see Sections 11.8.4 and 11.9). Avoided costs methods are also used to estimate some of the health-related benefits related to morbidity, such as hospital admissions (see Section 11.7).

Indirect market methods can also be used to infer the benefits of pollution reduction. The most important application of this technique for our analysis is the calculation of the value of a statistical life for use in the estimate of benefits from mortality reductions. There exists no market where changes in the probability of death are directly exchanged. However, people make decisions about occupation, precautionary behavior, and other activities associated with changes in the risk of death. By examining these risk changes and the other characteristics of people's choices, it is possible to infer information about the monetary values associated with changes in mortality risk (see Section 11.7). For measurement of health benefits, this analysis captures the WTP for most use and non-use values, with the exception of the value of avoided hospital admissions, which only captures the avoided cost of illness.

The most direct way to measure the economic value of air quality changes is in cases where the endpoints have market prices. For the final rule, this can only be done for effects on commercial agriculture and forestry. Well-established economic modeling approaches are used to predict price changes that result from predicted changes in agricultural and forestry outputs. Consumer and producer surplus measures can then be developed to give reliable indications of the benefits of changes in ambient air quality for these categories (see Section 11.8.2).

Estimating benefits for visibility and ecosystem services is a more difficult and less precise exercise because the endpoints are not directly or indirectly valued in markets. For example, the loss of a species of animal or plant from a particular habitat does not have a well-defined price. The contingent valuation method (CVM) has been employed in the economics literature to value endpoint changes for both visibility and ecosystem functions (Chestnut and Dennis, 1997). CVM values endpoints by using carefully structured surveys to ask a sample of people what amount of compensation is equivalent to a given change in environmental quality. There is an extensive scientific literature and body of practice on both the theory and technique of CVM. EPA believes that well-designed and well-executed CVM studies are valid for estimating the benefits of air quality regulation[1].

11.6 Methods for Describing Uncertainty

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty[2]. This analysis is no exception. As outlined both in this and preceding chapters, there are many inputs used to derive the final estimate of benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological estimates of concentration-response (C-R) functions, estimates of values (both from WTP and cost-of-illness studies), population estimates, income estimates, and estimates of the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs may be uncertain, and depending on their location in the benefits analysis, may have a disproportionately large impact on final estimates of total benefits. For example, emissions estimates are used in the first stage of the analysis. As such, any uncertainty in emissions estimates will be propagated through the entire analysis. When compounded with

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[1]Concerns about the reliability of value estimates that come from CVM studies have dominated debates about the methodology, since research has shown that bias can be introduced easily into these studies, especially if they are not carefully done. Accurately measuring willingness to pay for avoided health and welfare losses depends on the reliability and validity of the data collected. There are several issues to consider when evaluating study quality, including but not limited to 1) whether the sample estimates of WTP are representative of the population WTP; 2) whether the good to be valued is comprehended and accepted by the respondent; 3) whether the WTP elicitation format is designed to minimize strategic responses; 4) whether WTP is sensitive to respondent familiarity with the good, to the size of the change in the good, and to income; 5) whether the estimates of WTP are broadly consistent with other estimates of WTP for similar goods; and 6) the extent to which WTP responses are consistent with established economic principles.

[2] It should be recognized that in addition to uncertainty, the annual benefit estimates for the Section 126 Rule presented in this RIA are also inherently variable, due to the truly random processes that govern pollutant emissions and ambient air quality in a given year. Factors such as electricity demand and weather display constant variability regardless of our ability to accurately measure them. As such, the estimates of annual benefits should be viewed as representative of the types of benefits that will be realized, rather than the actual benefits that would occur every year.

uncertainty in later stages, small uncertainties in emission levels can lead to much larger impacts on total benefits. A more thorough discussion of uncertainty can be found in the benefits technical support document (TSD) for this RIA, *Section 126 Final Rule: Air Quality Estimation, Selected Health and Welfare Benefits Methods, and Benefit Analysis Results* (Abt Associates, 1999).

Some key sources of uncertainty in each stage of the benefits analysis are:

- gaps in scientific data and inquiry
- variability in estimated relationships, such as C-R functions, introduced through differences in study design and statistical modeling
- errors in measurement and projection for variables such as population growth rates
- errors due to misspecification of model structures, including the use of surrogate variables, such as using PM_{10} when $PM_{2.5}$ is not available, excluded variables, and simplification of complex functions
- biases due to omissions or other research limitations.

Some of the key uncertainties in the benefits analysis are presented in Table 11-2. Given the wide variety of sources for uncertainty and the potentially large degree of uncertainty about any primary estimate, it is necessary for us to address this issue in several ways. These include qualitative discussions, probabilistic assessments, and alternative calculations. For some parameters or inputs it may be possible to provide a statistical representation of the underlying uncertainty distribution. For other parameters or inputs, the information necessary to estimate an uncertainty distribution is not available. Even for individual endpoints, there is usually more than one source of uncertainty. This makes it difficult to provide a quantified uncertainty estimate. For example, the C-R function used to estimate avoided premature mortality has an associated standard error which represents the sampling error around the pollution coefficient in the estimated C-R function. It would be possible to report a confidence interval around the estimated incidences of avoided premature mortality based on this standard error. However, this would omit the contribution of air quality changes, baseline population incidences, projected populations exposed, and transferability of the C-R function to diverse locations to uncertainty about premature mortality. Thus, a confidence interval based on the standard error would provide a misleading picture about the overall uncertainty in the estimates. Information on the uncertainty surrounding particular C-R and valuation functions is provided in the TSD for this RIA (Abt Associates, 1999). But, this information should be interpreted within the context of the larger uncertainty surrounding the entire analysis. Below, we briefly discuss uncertainty for the major steps in the benefits analysis.

Uncertainty in the emissions and air quality estimates is both difficult and expensive to quantify. As such, we provide only a qualitative discussion along with our determination of the likely magnitude of the uncertainty and the probable direction of the bias. Some of the primary uncertainties in emissions and air quality are presented in Table 10-7 in Chapter 10.

There are several types of uncertainty surrounding the estimates of the C-R and economic valuation functions. We are able to quantify the uncertainty related to sampling error by using the parameters of the estimated distribution for each function (i.e. the mean and standard deviation for a normally distributed estimate). These uncertainty estimates are used to show the effects of measurement error on the estimates of total benefits in a set of alternative calculations included in Table 11-16[3]. However, we are not able to quantify model uncertainty for these functions. To characterize model uncertainty surrounding C-R and valuation functions, we provide a qualitative discussion and in some cases, an alternative calculation. The primary model uncertainties in C-R and economic valuation functions are presented in Table 11-2.

Our approach to characterizing model uncertainty in the estimate of total benefits is to present a primary estimate, based on the best available scientific literature and methods, and to then provide alternative calculations to illustrate the effects of uncertainty about key analytical assumptions. We do not attempt to assign probabilities to these alternative calculations, as we believe this would only add to the uncertainty of the analysis or present a false picture about the precision of the results[4]. Instead, the reader is invited to examine the impact of applying the different assumptions on the estimate of total benefits. While it is possible to combine all of the alternative calculations with a positive impact on benefits to form a "high" estimate or all of the alternative calculations with a negative impact on benefits to form a "low" estimate, this would not be appropriate because the probability of all of these alternative assumptions occurring simultaneously is extremely low. Instead, the alternative calculations are intended to demonstrate the sensitivity of our benefits results to key parameters which may be uncertain. Alternative calculations are presented in Table 11-16.

Many benefits categories, while known to exist, do not have enough information available to provide a quantified or monetized estimate. The uncertainty regarding these endpoints is such that we could determine neither a primary estimate nor a plausible range of values.

Our estimate of total benefits should be viewed as an approximate result because of the sources of uncertainty discussed above (see Table 11-2). The total benefits estimate may understate or overstate actual benefits of the rule. The remainder of this section describes in

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[3]In the table of alternative calculations (Table 11-16), we provide estimates of the 5th and 95th percentile values of a distribution of benefits based on this type of measurement uncertainty, assuming that all other model inputs are treated as fixed. Estimates of the 5th and 95th percentile values of distributions for all individual endpoints are provided in the TSD for this RIA (Abt Associates, 1999). Again, these estimates reflect only one type of uncertainty and should not be interpreted as probabilistic bounds on the benefits estimates.

[4] Some recent benefit-cost analyses in Canada and Europe (Holland, et al., 1999; Lang, et al., 1995) have estimated ranges of benefits by assigning *ad hoc* probabilities to ranges of parameter values for different endpoints. Although this does generate a quantitative estimate of an uncertainty range, the estimated points on these distributions are themselves highly uncertain and very sensitive to the subjective judgements of the analyst. To avoid these subjective judgements, we choose to allow the reader to determine the weights they would assign to alternative estimates.

Table 11-2.
Primary Sources of Uncertainty in the Benefit Analysis

1. Uncertainties Associated With Concentration-Response Functions
-The value of the ozone- or PM-coefficient in each C-R function. -Application of a single C-R function to pollutant changes and populations in all locations. -Similarity of future year C-R relationships to current C-R relationships. -Correct functional form of each C-R relationship. -Extrapolation of C-R relationships beyond the range of ozone or PM concentrations observed in the study.
2. Uncertainties Associated With Ozone and PM Concentrations
-Estimating future-year baseline and hourly ozone and daily PM concentrations. -Estimating the change in ozone and PM resulting from the control policy.
3. Uncertainties Associated with PM Mortality Risk
-No scientific literature supporting a direct biological mechanism for observed epidemiological evidence. -Direct causal agents within the complex mixture of PM responsible for reported health effects have not been identified. -The extent to which adverse health effects are associated with low level exposures that occur many times in the year versus peak exposures. -Possible confounding in the epidemiological studies of $PM_{2.5}$, effects with other factors (e.g., other air pollutants, weather, indoor/outdoor air, etc.). -The extent to which effects reported in the long-term studies are associated with historically higher levels of PM rather than the levels occurring during the period of study. -Reliability of the limited ambient $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.
4. Uncertainties Associated With Possible Lagged Effects
-What portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels would occur in a single year, and what portion might occur in subsequent years.
5. Uncertainties Associated With Baseline Incidence Rates
-Some baseline incidence rates are not location-specific (e.g., those taken from studies) and may therefore not accurately represent the actual location-specific rates. -Current baseline incidence rates may not well approximate what baseline incidence rates will be in the year 2007. -Projected population and demographics -- used to derive incidences – may not well approximate future-year population and demographics.
6. Uncertainties Associated With Economic Valuation
-Unit dollar values associated with health and welfare endpoints are only estimates of mean WTP and therefore have uncertainty surrounding them. -Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates due to differences in income or other factors.
7. Uncertainties Associated With Aggregation of Monetized Benefits
-Health and welfare benefits estimates are limited to the available C-R functions. Thus, unquantified benefit categories will cause total benefits to be underestimated.

greater detail two potential sources of uncertainty that can impact multiple aspects of the analysis: 1) the inability to quantify or monetize many of the benefits and costs associated with the rule; and 2) adjustments for changes in income in the future.

11.6.1 Unquantifiable Environmental Benefits and Costs

In considering the monetized benefits estimates, the reader should remain aware of the many limitations for conducting these analyses mentioned throughout this RIA. One significant limitation of both the health and welfare benefits analyses is the inability to quantify many of the PM and ozone-induced adverse effects listed in Table 11-1. For many health and welfare effects, such as PM-related materials damage, reliable C-R functions and/or valuation functions are not currently available. For others, such as health and welfare effects associated with ozone, time constraints prevented their inclusion in this analysis. In general, if it were possible to monetize these benefits categories, the benefits estimates presented in this analysis would increase[5]. Unquantified benefits are qualitatively discussed in the health and welfare effects sections. In addition to unquantified benefits, there may also be environmental costs that we are unable to quantify. Several of these environmental cost categories are related to nitrogen deposition, while one category is related to the issue of ultraviolet light. These endpoints are qualitatively discussed in the health and welfare effects sections as well. The net effect of excluding benefit and disbenefit categories from the estimate of total benefits depends on the relative magnitude of the effects.

11.6.2 Projected Income Growth

Our analysis does not attempt to adjust benefits estimates to reflect expected growth in real income. Economic theory argues, however, that WTP for most goods (such as environmental protection) will increase if real incomes increase. There is substantial empirical evidence that the income elasticity[6] of WTP for health risk reductions is positive, although there is uncertainty about its exact value. While many analyses assume that the income elasticity of WTP is unit elastic (i.e., ten percent higher income level implies a ten percent higher willingness to pay to reduce risk changes), empirical evidence suggests that income elasticity is substantially less than one and thus inelastic. The effects of income changes on WTP estimates can influence benefit estimates in two different ways: (1) as changes that reflect estimates of income change in the affected population over time; and (2) as changes based on differences in income between study

[5] While we are unable to provide quantified ozone benefits based on air quality modeling for this analysis, we develop an estimate of projected ozone benefits in Chapter 12 for use in comparing benefits and costs. True ozone benefits may be greater or less than this projected estimate, but should be approximately the same order of magnitude.

[6] Income elasticity is a common economic measure equal to the percentage change in WTP for a one percent change in income.

populations and the affected populations at a particular time. Empirical evidence of the effect of income on WTP gathered to date is based on studies examining the latter. Income elasticity adjustments to better account for changes over time, therefore, will necessarily be based on potentially inappropriate data. The degree to which WTP may increase for the specific health and welfare benefits provided by the Section 126 rule is not estimated due to the high degree of uncertainty in the income elasticity information.

11.7 Assessment of Human Health Benefits

The most significant monetized benefits of reducing ambient concentrations of PM and ozone are attributable to reductions in health risks associated with air pollution. EPA's criteria documents for ozone and PM list numerous health effects known to be linked to ambient concentrations of these pollutants (EPA, 1996a, 1996b). This section describes individual effects and the methods used to quantify and monetize changes in the expected number of incidences of various health effects.

In section 11.7.1, we discuss how we have determined the baseline incidences for the health effects impacted by changes in PM and ozone. In section 11.7.2, we explain how we deal with the issue of health effects thresholds. In section 11.7.3, we describe how we quantify and value changes in individual health effects. Finally, in section 11.7.4 we present quantified estimates of the reductions in health effects resulting from the Section 126 rule and their associated monetary values.

11.7.1 Estimating Baseline Incidences for Health Effects

The epidemiological studies of the association between pollution levels and adverse health effects generally provide a direct estimate of the relationship of air quality changes to the relative risk of a health effect, rather than an estimate of the absolute number of avoided cases. For example, a typical result might be that a ten $\mu g/m^3$ decrease in daily $PM_{2.5}$ levels might decrease hospital admissions by three percent. The baseline incidence of the health effect is necessary to convert this relative change into a number of cases.

Because most PM and ozone studies that estimate C-R functions for mortality considered only non-accidental mortality, we adjusted county-specific baseline total mortality rates used in the estimation of PM- and ozone-related mortality to provide a better estimate of county-specific non-accidental mortality. We multiplied each county-specific mortality rate by the ratio of national non-accidental mortality to national total mortality (0.93) (U.S. Centers for Disease Control, 1999a). An additional adjustment was necessary to provide baseline incidences for adults 30 and older for use in the Pope, et al. (1995) PM mortality C-R function. We estimated county-specific baseline mortality incidences for this population by applying national age-specific death rates to county-specific age distributions, and adjusting the resulting estimated age-specific incidences so that the estimated total incidences (including all ages) equals the actual county-specific total incidences.

County-level incidence rates are not available for other endpoints. We used national incidence rates whenever possible, because these data are most applicable to a national assessment of benefits. However, for some studies, the only available incidence information comes from the studies themselves; in these cases, incidence in the study population is assumed to represent typical incidence at the national level.

11.7.2 Accounting for Potential Health Effect Thresholds

When conducting clinical (chamber) and epidemiological studies, C-R functions may be estimated with or without explicit thresholds. Air pollution levels below the threshold are assumed to have no associated adverse health effects. When a threshold is not assumed, as is often the case in epidemiological studies, any exposure level is assumed to pose a non-zero risk of response to at least one segment of the population.

The possible existence of an effect threshold is a very important scientific question and issue for policy analyses such as the Section 126 regulatory impact analysis. In the benefits analysis for the Section 126 Proposal/Final NOx SIP Call RIA, the low-end estimate of benefits assumed a threshold in PM health effects at 15 $\mu g/m^3$. However, the most recent advice from EPA's Science Advisory Board is that there is currently no scientific basis for selecting a threshold of 15 $\mu g/m^3$ or any other specific threshold for the PM-related health effects considered in this analysis (EPA-SAB-Council-ADV-99-012, 1999). Therefore, for our benefits analysis of the final Section 126 rule, we assume there is a zero threshold for the purposes of modeling health effects. It is not appropriate to adopt a threshold for use in either the primary analysis or any alternative calculations because there is no adequate scientific evidence to support such a calculation. The potential impact of a health effects threshold on avoided incidences of PM-related premature mortality is explored as a key sensitivity analysis presented in Appendix A.

11.7.3 Quantifying and Valuing Individual Health Endpoints

Health benefits of the Section 126 rule may be related to ozone only, PM only, or both pollutants. The ozone only health effects included in our primary benefits estimate are chronic asthma in adult males and decreased worker productivity. The PM only health effects include premature mortality, chronic bronchitis, acute bronchitis, upper and lower respiratory symptoms, shortness of breath, and work loss days[7]. The health effects related to both PM and ozone include

[7] In the benefits analysis for the Section 126 Proposal/Final NOx SIP Call RIA, we also estimated reductions in the incidence of premature mortality associated with reduced exposures to ozone. At least some evidence has been found linking both PM and ozone with premature mortality. The SAB has raised concerns that

hospital admissions, and minor restricted activity days.

For this analysis, we rely on C-R functions estimated in published epidemiological studies relating adverse health effects to ambient air quality. The specific studies from which C-R functions are drawn are included in Table 11-3. A complete discussion of the C-R functions used for this analysis is contained in the benefits TSD for this RIA (Abt Associates, 1999).

While a broad range of adverse health effects have been associated with exposure to elevated ozone and PM levels (as noted for example in Table 11-1 and described more fully in the ozone and PM criteria documents (EPA, 1996a, 1996b), we include only a subset of health effects in this quantified benefit analysis. Health effects are excluded from this analysis for three reasons: (1) the possibility of double counting (such as hospital admissions for specific respiratory diseases); (2) uncertainties in applying effect relationships based on clinical studies to the affected population; or (3) a lack of an established C-R relationship.

When a single published study is selected as the basis of the C-R relationship between a pollutant and a given health effect, or "endpoint," applying the C-R function is straightforward. This is the case for most of the health endpoints selected for inclusion in the benefits analysis. A single C-R function may be chosen over other potential functions because the underlying epidemiological study used superior methods, data or techniques, or because the C-R function is more generalized and comprehensive.

When several estimated C-R relationships between a pollutant and a given health endpoint have been selected, they are combined or pooled to derive a single estimate of the relationship. A separate TSD provides details of the procedures used to combine multiple C-R functions (Abt Associates, 1999). Pooled C-R functions are used to estimate incidences of chronic bronchitis related to PM exposure, hospital admissions from cardiovascular and respiratory causes related to PM and ozone exposure, and emergency room visits for asthma related to PM and ozone exposure.

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mortality-related benefits of air pollution reductions may be overstated if separate pollutant-specific estimates, some of which may have been obtained from models excluding the other pollutants, are aggregated. In addition, there may be important interactions between pollutants and their effect on mortality (EPA-SAB-Council-ADV-99-012, 1999)

The Pope et al. (1995) study used to quantify PM-related mortality included only PM, so it is unclear to what extent it may include the impacts of ozone or other gaseous pollutants. Because of concern about overstating of benefits and because the evidence associating mortality with exposure to particulate matter is currently stronger than for ozone, only the benefits of PM-related premature mortality avoided are included in the total benefits estimate. The benefits associated with ozone reductions are presented as a sensitivity analysis in Appendix A but are not included in the estimate of total benefits.

Table 11-3.
Quantified Endpoints and Studies Included in the Primary Analysis

Endpoint	Pollutant	Study	Study Population
Mortality			
Ages 30 and Older	PM	Pope et al. (1995)	30 and older
Chronic Illness			
Chronic Bronchitis	PM	Multiple Studies	Multiple Studies
Chronic Asthma	Ozone	McDonnell et al. (1999)	Non-asthmatics, 27 and older
Hospital Admissions			
All Respiratory	PM, Ozone	Multiple Studies	Multiple Studies
Total Cardiovascular	PM, Ozone	Multiple Studies	Multiple Studies
Asthma-Related ER Visits	PM, Ozone	Multiple Studies	Multiple Studies
Other Illness			
Acute Bronchitis	PM	Dockery et al. (1996)	8-12
Upper Respiratory Symptoms	PM	Pope et al. (1991)	Asthmatics 9-11
Lower Respiratory Symptoms	PM	Schwartz et al. (1994)	7-14
Shortness of Breath	PM	Ostro et al. (1995)	African American asthmatics, 7-12
Work Loss Days	PM	Ostro (1987)	18-65
Minor Restricted Activity Days / Any of 19 respiratory Symptoms	PM, Ozone	Multiple Studies	Multiple Studies

Whether the C-R relationship between a pollutant and a given health endpoint is estimated by a single function from a single study or by a pooled function of C-R functions from several studies, we apply that same C-R relationship at all locations in the U.S. Although the C-R relationship may in fact vary somewhat from one location to another (for example, due to differences in population susceptibilities or differences in the composition of PM), location-specific C-R functions are generally not available. While a single function applied everywhere may result in overestimates of incidence changes in some locations and underestimates in other locations, these location-specific biases will to some extent cancel each other out when the total incidence change is calculated. It is not possible to know the extent or direction of the bias in the total incidence change based on the general application of a single C-R function everywhere.

The appropriate economic value of a change in a health effect depends on whether the health effect is viewed ex ante (before the effect has occurred) or ex post (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health affects by a fairly small amount for a large population. The appropriate economic measure is therefore ex-ante WTP for changes in risk.   However, epidemiological studies generally provide estimates of the expected number of incidences of a particular health effect avoided due to a reduction in air pollution. A convenient way to use this data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a measure is able to reduce the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $100, then the WTP for an avoided statistical premature mortality amounts to $1 million ($100/0.0001 change in risk). Using this approach, the size of the affected population is automatically taken into account by the number of incidences predicted by epidemiological studies applied to the relevant population. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as an alternative estimate. For example, for the valuation of hospital admissions we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These costs of illness (COI) estimates generally understate the true value of avoiding a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect. Table 11-4 summaries the value estimates per health effect that we use in this analysis. Alternative values used to derive the alternative estimates listed in Table 11-16 are indicated in parentheses. Note that there is not a specific value listed for hospital admissions. This reflects the fact that there are a range of symptoms for which individuals are admitted, each of which has a different associated cost. The estimated benefit of avoided hospital admissions reflects the distribution of symptoms across the total incidence of hospital admissions. The study-specific values for hospital admissions can be found in the benefits TSD for this RIA (Abt Associates, 1999).

In the following sections, we describe individual health endpoints and the C-R functions we have selected to provide quantified estimates of the avoided health effects associated with the Section 126 rule. In addition, we discuss how these changes in health effects should be valued and indicate the value functions selected to provide monetized estimates of the value of changes in health effects.

Table 11-4.
Unit Values Used for Economic Valuation of Health Endpoints

Health or Welfare Endpoint	Estimated Value Per Incidence (1997$) Central Estimate	Derivation of Estimates
Mortality	$5.9 million per statistical life	Value is the mean of value-of-statistical-life estimates from 26 studies (5 contingent valuation and 21 labor market studies) reviewed for the §812 retrospective analysis.
Chronic Bronchitis (CB)	$319,000	Value is the mean of a generated distribution of WTP to avoid a case of pollution-related CB. WTP to avoid a case of pollution-related CB is derived by adjusting WTP (as described in Viscusi et al., 1991) to avoid a severe case of CB for the difference in severity and taking into account the elasticity of WTP with respect to severity of CB.
Chronic Asthma	$31,000	Based on results reported in two studies (Blumenschein and Johannesson, 1998; O'Connor and Blomquist, 1997). Assumes a 5% discount rate and reflects adjustments for age distribution among adults (ages 27 and older) and projected life years remaining.
Hospital Admissions		
All Respiratory (ICD codes: 460-519)	variable — function of the analysis	The COI estimates are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total respiratory illnesses) reported in Elixhauser (1993).
All Cardiovascular (ICD codes: 390-429)	variable — function of the analysis	The COI estimates are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular illnesses) reported in Elixhauser (1993).
Emergency room visits for asthma	$280	COI estimate based on data reported by Smith et al. (1997).
Respiratory Ailments Not Requiring Hospitalization		
Upper Respiratory Symptoms (URS)	$23	Combinations of the 3 symptoms for which WTP estimates are available that closely match those listed by Pope et al. result in 7 different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for URS is the average of the dollar values for the 7 different types of URS.
Lower Respiratory. Symptoms (LRS)	$15	Combinations of the 4 symptoms for which WTP estimates are available that closely match those listed by Schwartz et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS.
Acute Bronchitis	$55	Average of low and high values recommended for use in section 812 analysis (IEc 1994).

Health or Welfare Endpoint	Estimated Value Per Incidence (1997$) Central Estimate	Derivation of Estimates
Shortness of breath, chest tightness or wheezing	$6.50	From Ostro et al. (1995). This is the mean of the median estimates from two studies of WTP to avoid a day of shortness of breath: Dickie et al. (1991) ($0.00), and Loehman et al. (1979) ($13.00).
Restricted Activity and Work Loss Days		
Work Loss Days (WLDs)	Variable	Regionally adjusted median weekly wage for 1990 divided by 5 (adjusted to 1997$) (U.S. Bureau of the Census, 1992).
Minor Restricted Activity Days (MRADs)	$47	Median WTP estimate to avoid 1 MRRAD – minor respiratory restricted activity day -- from Tolley et al.(1986) .

11.7.3.1 Premature Mortality: Quantification

Both acute and chronic exposures to ambient levels of air pollution have been associated with increased risk of premature mortality. Because of the extreme nature of this endpoint and the high monetary value associated with risks to life, reductions in the risk of premature mortality are the most important health endpoint quantified in this analysis, accounting for over 85 percent of the total monetized benefits. However, considerable uncertainty exists, both among economists and policymakers, as to the appropriate way to value reductions in mortality risks. Because of these factors, we include a more detailed discussion for premature mortality than for other health effects.

Health researchers have consistently linked air pollution, especially PM, with increases in premature mortality. A substantial body of published scientific literature recognizes a correlation between elevated PM concentrations and increased mortality rates. Much of this literature is summarized in the 1996 PM Criteria Document (U.S. EPA, 1996a). There is much about this relationship that is still uncertain, however, as stated in preamble to the 1997 PM National Ambient Air Quality Standards (U.S. EPA. 40 CFR 50, 1997), “the consistency of the results of the epidemiological studies from a large number of different locations and the coherent nature of the observed effects are suggestive of a likely causal role of ambient PM in contributing to the reported effects,” which include premature mortality. The National Academy of Sciences, in their report on research priorities for PM (National Academy of Sciences, 1998), indicate that “there is a great deal of uncertainty about the implications of the findings [of an association between PM and premature mortality] for risk management, due to the limited scientific information about the specific types of particles that might cause adverse health effects, the contributions of particles of outdoor origin to actual human exposures, the toxicological mechanisms by which the particles might cause adverse health effects, and other important questions.” EPA acknowledges these uncertainties, however, for this analysis, we assume a causal relationship between exposure to elevated PM and premature mortality, based on the consistent evidence of a correlation between PM and mortality reported in the scientific literature (U.S. EPA, 1996a).

It is currently unknown whether there is a time lag (a delay between changes in PM exposures and changes in mortality rates) in the chronic PM/premature mortality relationship. The existence of such a lag is important for the valuation of premature mortality incidences because economic theory suggests that benefits occurring in the future should be discounted. Although there is no specific scientific evidence of the existence or structure of a PM effects lag, current scientific literature on adverse health effects, such as those associated with PM (e.g., smoking-related disease) and the difference in the effect size between chronic exposure studies and daily mortality studies suggest that all incidences of premature mortality reduction associated with a given incremental change in PM exposure probably would not occur in the same year as the exposure reduction. This same smoking-related literature implies that lags of up to a few years are plausible. Adopting the lag structure used in a illustrative calculation for the Tier II proposal RIA and endorsed by the SAB (EPA-SAB-COUNCIL-ADV-00-001, 1999), we assume a five-year lag structure, with 25 percent of premature deaths occurring in the first year, another 25 percent in the second year, and 16.7 percent in each of the remaining three years. To explore the uncertainty surrounding this lag structure, Appendix A contains a sensitivity analysis showing how different lag structures affect the estimated value of reductions in premature mortality.

Two types of exposure studies (short-term and long-term) have been used to estimate a PM/premature mortality relationship. Short-term exposure studies attempt to relate short-term (often day-to-day) changes in PM concentrations and changes in daily mortality rates up to several days after a period of elevated PM concentrations. Long-term exposure studies examine the potential relationship between longer-term (e.g., annual) changes in exposure to PM and annual mortality rates. Researchers have found significant correlations using both types of studies (U.S. EPA, 1996a); however, for this analysis, following SAB advice (EPA-SAB-COUNCIL-ADV-99-005, 1999) we rely exclusively on long-term studies to quantify PM mortality effects.

Following guidance from the SAB (EPA-SAB-COUNCIL-ADV-99-005, 1999), we prefer studies to use long-term studies that employ a prospective cohort design over those that use an ecologic or population-level design. Prospective cohort studies follow individuals forward in time for a specified period, periodically evaluating each individual's exposure and health status. While the long-term study design is preferred, they are expensive to conduct and consequently there are relatively few well designed long-term studies. For PM, there have been only a few, and the SAB has explicitly recommended use of only one — the Pope, et al. (1995) prospective cohort study in estimating avoided premature mortality from reductions in ambient PM concentrations (EPA-SAB-COUNCIL-ADV-99-005, 1999). We follow this recommendation and are consistent with the modeling of mortality effects of PM in both the Section 812 Retrospective and Prospective Reports to Congress. The Pope et al. study is recommended in preference to other available long-term studies because it uses better statistical methods, has a much larger sample size, the longest exposure interval, and more locations (51 cities) in the United States than other studies.

Although we use the Pope study exclusively to derive our primary estimates of avoided premature mortality, the C-R function based on Dockery et al. (1993) may provide a reasonable alternative estimate (EPA-SAB-COUNCIL-ADV-99-012, 1999). While the Dockery et al. study used a smaller sample of individuals from fewer cities than the study by Pope et al., it features improved exposure estimates, a slightly broader study population (adults aged 25 and older), and a follow-up period nearly twice as long as that of Pope et al. The Dockery et al. (1993) study finds a larger effect of PM on premature mortality. We present an alternative estimate of premature adult mortality associated with long-term PM exposure based on Dockery et al. (1993) in Table 11-16. We emphasize, however, that based on SAB advice, the Pope et al. (1995) derived estimate is our primary estimate of the effect of the final Section 126 rule on this important health effect**.**

11.7.3.2 Premature Mortality: Valuation

We estimate the monetary benefit of reducing premature mortality risk using the "value of statistical lives saved" (VSL) approach, even though the actual valuation is of small changes in mortality risk experienced by a large number of people. The VSL approach applies information from several value-of-life studies to determine a reasonable benefit of preventing premature mortality. The mean value of avoiding one statistical death is estimated to be $5.9 million in 1997 dollars. This represents an intermediate value from a variety of estimates that appear in the economics literature, and is a value EPA has frequently used in RIAs for other rules and in the Section 812 reports to Congress. This estimate is the mean of a distribution fitted to the estimates from 26 value-of-life studies identified in the Section 812 reports as "applicable to policy analysis." The approach and set of selected studies mirrors that of Viscusi (1992) (with the addition of two studies), and uses the same criteria as Viscusi in his review of value-of-life studies. The $5.9 million estimate is consistent with Viscusi's conclusion (updated to 1997$) that "most of the reasonable estimates of the value of life are clustered in the $3.7 to $8.6 million range." Five of the 26 studies are contingent valuation (CV) studies, which directly solicit WTP information from subjects; the rest are wage-risk studies, which base WTP estimates on estimates of the additional compensation demanded in the labor market for riskier jobs. The 26 studies used to form the distribution of the value of a statistical life are listed in Table 11-5. As indicated in the previous section on quantification of premature mortality benefits, we assume for this analysis that some of the incidences of premature mortality related to PM exposures occur in a distributed fashion over the five years following exposure. To take this into account in the valuation of reductions in premature mortality, we apply an annual five percent discount rate to the value of premature mortality occurring in future years.

The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. Some of the alternative approaches that have been proposed for valuing reductions in mortality risk are discussed in Text Box 1.

Table 11-5.
Summary of Mortality Valuation Estimates[a]

Study	Type of Estimate	Valuation per Statistical Life (millions of 1997 $)
Kneisner and Leeth (1991) (US)	Labor Market	0.7
Smith and Gilbert (1984)	Labor Market	0.9
Dillingham (1985)	Labor Market	1.1
Butler (1983)	Labor Market	1.4
Miller and Guria (1991)	Contingent Valuation	1.5
Moore and Viscusi (1988)	Labor Market	3.1
Viscusi et al. (1991)	Contingent Valuation	3.3
Gegax et al. (1985)	Contingent Valuation	4.1
Marin and Psacharopoulos (1982)	Labor Market	3.4
Kneisner and Leeth (1991) (Australia)	Labor Market	4.1
Gerking et al. (1988)	Contingent Valuation	4.2
Cousineau et al. (1988)	Labor Market	4.4
Jones-Lee (1989)	Contingent Valuation	4.7
Dillingham (1985)	Labor Market	4.8
Viscusi (1978; 1979)	Labor Market	5.0
R.S. Smith (1976)	Labor Market	5.6
V.K. Smith (1983)	Labor Market	5.8
Olson (1981)	Labor Market	6.4
Viscusi (1981)	Labor Market	8.0
R.S. Smith (1974)	Labor Market	8.8
Moore and Viscusi (1988)	Labor Market	9.0
Kneisner and Leeth (1991) (Japan)	Labor Market	9.3
Herzog and Schlottman (1987)	Labor Market	11.2
Leigh and Folson (1984)	Labor Market	11.9
Leigh (1987)	Labor Market	12.8
Garen (1988)	Labor Market	16.6

[a] Based on Viscusi (1992). The values in Viscusi have been updated to 1997 dollars, as detailed in Abt Associates, 1999.

Text Box 1
Alternative Approaches for Assessing the Value of Reduced Mortality Risk

Stated preference studies – These studies use survey responses to estimate WTP to avoid risks. *Strengths:* flexible approach allowing for appropriate risk context, good data on WTP for individuals. *Weaknesses:* Risk information may not be well-understood by respondents and questions may be unfamiliar.

Consumer market studies – These studies use consumer purchases and risk data (e.g. smoke detectors) to estimate WTP to avoid risks. *Strengths:* uses revealed preferences and is a flexible approach. *Weaknesses:* very difficult to estimate both risk and purchase variables.

Value of statistical life year – Provides an annual equivalent to value of statistical life estimates. *Strengths:* provides financially accurate adjustment for age at death. *Weaknesses:* adjustment may not reflect how individuals consider life-years; assumes equal value for all remaining life-years.

Quality adjusted life year – Applies quality of life adjustment to life-extension data, uses cost-effectiveness data to value. *Strengths:* widely used in public health literature to assess private medical interventions. *Weaknesses:* lack of data on health state indices and life quality adjustments that are applicable to an air pollution context.

WTP for a change in survival curve – Reflects WTP for change in risk, potentially incorporates age-specific nature of risk reduction. *Strengths:* theoretically preferred approach that most accurately reflects risk reductions from air pollution control. *Weaknesses:* almost no empirical literature available; difficulty in obtaining reliable values.

WTP for a change in longevity – Uses stated preference approach to generate WTP for longevity or longer life expectancy. *Strengths:* life expectancy is a familiar term to most individuals. *Weaknesses:* does not incorporate age-specific risk information; problems in adapting to air pollution context.

Cost-effectiveness – Determines the implicit cost of saving a life or life-year. *Strengths:* widely used in public health contexts. *Weaknesses:* health context is for private goods, dollar values do not necessarily reflect individual preferences. (Note: this is not the same as cost-effectiveness for emission reductions discussed in Chapters 6, 7 and 9 of this RIA.)

There is general agreement that the value to an individual of a reduction in mortality risk can vary based on several factors, including the age of the individual, the type of risk, the level of control the individual has over the risk, the level of risk aversion, and the health status of the individual. While the empirical basis for adjusting the $5.9 million VSL for many of these factors does not yet exist, a thorough discussion of these factors is contained in the benefits TSD for this RIA (Abt Associates, 1999). EPA recognizes the need for investigation by the scientific community to develop additional empirical support for adjustments to VSL for the factors mentioned above.

One important factor in Text Box 1 for which the impact on total benefits can be illustrated is the difference in age distribution between the population affected by air pollution and the population for which most of the VSL estimates were developed. To address this factor we use the "value of statistical life-years lost" (VSLY) approach, recommended by the SAB as an appropriate alternative to the VSL approach (EPA-SAB-COUNCIL-ADV-98-003, 1998). To employ the value of statistical life-year (VSLY) approach, we first estimated the age distribution of those lives projected to be saved by reducing air pollution. Based on life expectancy tables, we calculate the life-years saved from each statistical life saved within each age and gender cohort. To value these statistical life-years, we hypothesize a conceptual model that depicts the relationship between the value of life and the value of life-years. The average number of life-years saved across all age groups for which data were available is 14 for PM-related mortality. The average for PM, in particular, differs from the 35-year expected remaining lifespan derived from existing wage-risk studies. Using the same distribution of value of life estimates used above, we estimated a distribution for the value of a life-year and combined it with the total number of estimated life-years lost. The details of these calculations are presented in the TSD for this RIA (Abt Associates, 1999).

11.7.3.3 Chronic Bronchitis: Quantification

Chronic bronchitis is characterized by mucus in the lungs and a persistent wet cough for at least three months a year for several years in a row. Chronic bronchitis affects an estimated five percent of the U.S. population (American Lung Association, 1999). There are a limited number of studies that have estimated the impact of air pollution on chronic bronchitis. Schwartz (1993) and Abbey et al.(1993; 1995) provide the evidence that long-term PM exposure gives rise to the development of chronic bronchitis in the U.S. Following the Section 812 Prospective Report (U.S. EPA, 1999a), our analysis pools the estimates from these studies to develop a C-R function linking PM to chronic bronchitis.

It should be noted that Schwartz used data on the *prevalence* of chronic bronchitis, not its *incidence*. Following the §812 Prospective Report, we assume that it is appropriate to estimate the percentage change in the prevalence rate for chronic bronchitis using the estimated coefficient from Schwartz's study in a C-R function, and then to assume this percentage change applies to a baseline incidence rate obtained from another source. For example, if the prevalence declines by 25 percent with a drop in PM, then baseline incidence drops by 25 percent with the same drop in PM..

11.7.3.4 Chronic Bronchitis: Valuation

The best available estimate of WTP to avoid a case of chronic bronchitis (CB) comes from Viscusi et al. (1991)[8]. The Viscusi et al. study, however, describes a severe case of CB to the survey respondents. We therefore employ an estimate of WTP to avoid a pollution-related case of CB, based on adjusting an adjustment of the Viscusi et al. (1991) estimate of the WTP to avoid a sever case. This is done to account for the likelihood that an average case of pollution-related CB is not as severe. The adjustment is made by applying the elasticity of WTP with respect to severity reported in the Krupnick and Cropper (1992) study. Details of this adjustment procedure are provided in the benefits TSD for this RIA (Abt Associates, 1999).

We use the mean of a distribution of WTP estimates as the central tendency estimate of WTP to avoid a pollution-related case of CB in this analysis. The distribution incorporates uncertainty from three sources: (1) the WTP to avoid a case of severe CB, as described by Viscusi et al.; (2) the severity level of an average pollution-related case of CB (relative to that of the case described by Viscusi et al.; and (3) the elasticity of WTP with respect to severity of the illness. Based on assumptions about the distributions of each of these three uncertain components, we derive a distribution of WTP to avoid a pollution-related case of CB by statistical uncertainty analysis techniques. The expected value (i.e., mean or average) of this distribution, which is about $320,000 (1997$), is taken as the central tendency estimate of WTP to avoid a PM-related case of CB. We describe the three underlying distributions, and the generation of the resulting distribution of WTP, in the benefits TSD for this RIA (Abt Associates, 1999).

11.7.3.5 Chronic Asthma: Quantification

Chronic asthma is characterized by repeated incidences of inflammation of the lungs. This causes restriction in the airways and results in shortness of breath, wheezing, and coughing. Asthma is also characterized by airway hyper responsiveness to stimuli. Chronic asthma affects over seven percent of the U.S. population (U.S. Centers for Disease Control, 1999b). Most studies have not identified an association between air quality and asthma. However, a recent study by McDonnell et al. (1999) provides a statistical association between ozone and the development of asthma in adult white, non-Hispanic males. Following the advice of the EPA Science Advisory Board (EPA-SAB-COUNCIL-ADV-00-001, 1999) and the Section 812 Prospective Report, we have added this significant health effect to our benefit analysis since the proposal RIA. However, it should be

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[8] The Viscusi et al. (1991) study was an experimental study intended to examine new methodologies for eliciting values for morbidity endpoints. Although these studies were not specifically designed for policy analysis, the EPA Science Advisory Board (EPA-SAB-COUNCIL-ADV-00-002, 1999) has indicated that the severity adjusted values from this study provide reasonable estimates of the WTP for chronic bronchitis. As with other contingent valuation studies, the reliability of the WTP estimates depends on the methods used to obtain the WTP values.

noted that it is not clear that the intermittent, short-term, and relatively small changes in annual average ozone concentrations resulting from this rule are likely to measurably change long-term risks of asthma. The McDonnell et al. study is a prospective cohort analysis, measuring the association between long-term exposure to ambient concentrations of ozone and development of chronic asthma in adults. The study found a statistically significant effect for adult males, but none for adult females.

Some commentors have raised questions about the statistical validity of the associations found in this study and the appropriateness of transferring the estimated C-R function from the study populations (white, non-Hispanic males) to other male populations (i.e. African-American males). Some of these concerns include 1) no significant association was observed for female study participants also exposed to ozone; 2) the estimated C-R function is based on a cross-sectional comparison of ozone levels, rather than incorporating information on ozone levels over time; 3) information on the accuracy of self-reported incidence of chronic asthma was collected but not used in estimating the C-R function; 4) the study may not be representative of the general population because it included only those individuals living 10 years or longer within 5 miles of their residence at the time of the study; and 5) the study had a significant number of study participants drop out, either through death, loss of contact, or failure to provide complete or consistent information.

EPA believes that while these issues may result in increased uncertainty about this effect, none can be identified with a specific directional bias in the estimates. In addition, the study has been reviewed by the SAB and has been specifically recommended for inclusion in benefits analyses of changes in ozone concentrations (EPA-SAB-COUNCIL-ADV-00-001, 1999). EPA also believes it to be appropriate to apply the C-R function to all adult males over age 27 because no evidence exists to suggest that non-white adult males have a lower responsiveness to air-pollution. For other health effects such as shortness of breath, where the study population was limited to a specific group potentially more sensitive to air pollution than the general population (Ostro, et al., 1995), EPA has applied the C-R function only to the limited population. EPA recognizes the need for further investigation by the scientific community to confirm the statistical association identified in the McDonnell et al. study.

11.7.3.6 Chronic Asthma: Valuation

Similar to the valuation of chronic bronchitis, WTP to avoid chronic asthma is presented as the net present value of what would potentially be a stream of costs and lower well-being incurred over a lifetime. Estimates of WTP to avoid asthma are provided in two studies, one by Blumenschein and Johannesson (1998) and one by O'Conor and Blomquist (1997). Both studies use the contingent valuation method to solicit annual WTP estimates from individuals who have been diagnosed as asthmatics. The central estimate of lifetime WTP to avoid a case of chronic asthma among adult males, approximately $25,000, is the average of the present discounted value from the two studies. Details of the derivation of this central estimate from the two studies is provided in the benefits TSD for this RIA (Abt Associates, 1999).

11.7.3.7 Hospital Admissions: Quantification

There is a wealth of epidemiological information on the relationship between air pollution and hospital admissions for various respiratory and cardiovascular diseases; in addition, some studies have examined the relationship between air pollution and emergency room (ER) visits. Because most emergency room visits do not result in an admission to the hospital (the majority of people going to the ER are treated and return home) we treat hospital admissions and ER visits separately, taking account of the fraction of ER visits that do get admitted to the hospital.

Hospital admissions require the patient to be examined by a physician, and on average may represent more serious incidents than ER visits. The two main groups of hospital admissions estimated in this analysis are respiratory admissions and cardiovascular admissions. There is not much evidence linking ozone or PM with other types of hospital admissions. The only type of ER visits that have been linked to ozone and PM in the U.S. or Canada are asthma-related visits. To estimate the number of hospital admissions for respiratory illness, cardiovascular illness, and asthma ER visits, we pool the incidence estimates from a variety of U.S. and Canadian studies, using a random effects weighting procedure[9]. Details of the pooling procedure and a complete listing of the hospital admission studies used in our estimates can be found in the benefits TSD for this RIA (Abt Associates, 1999).

11.7.3.8 Hospital Admissions: Valuation

An individual's WTP to avoid a hospital admission will include, at a minimum, the amount of money he or she pays for medical expenses (i.e., payment towards the hospital charge and the associated physician charge) and the loss in earnings. In addition, an individual is likely to be willing to pay some amount to avoid the pain and suffering associated with the illness itself. Even if they incurred no medical expenses and no loss in earnings, most individuals would still be willing to pay something to avoid the illness.

In the absence of estimates of WTP to avoid hospital admissions for specific illnesses, estimates of total cost-of-illness (COI) are typically used as conservative estimates. These estimates are biased downward because they do not include the value of avoiding the illness itself. Some analyses adjust COI estimates upward by multiplying by an estimate of the ratio of WTP to

[9] Because we are estimating ER visits as well as hospital admissions for asthma, we must avoid counting twice the ER visits for asthma that are subsequently admitted to the hospital. To avoid double-counting, the baseline incidence rate for emergency room visits is adjusted by subtracting the percentage of patients that are admitted into the hospital. The reported incidence rates suggest that ER visits for asthma occur 2.7 times as frequently as hospital admissions for asthma. The baseline incidence of asthma ER visits is therefore taken to be 2.7 times the baseline incidence of hospital admissions for asthma. To avoid double-counting, however, only 63% of the resulting change in asthma ER visits associated with a given change in pollutant concentrations is counted in the ER visit incidence change.

COI, to better approximate total WTP. Other analyses have avoided making this adjustment because of the possibility of over adjusting -- that is, possibly replacing a known downward bias with an upward bias. Consistent with the guidance offered by the EPA Science Advisory Board, the COI values used in this benefits analysis will not be adjusted to better reflect the total WTP (EPA-SAB-COUNCIL-ADV-98-003, 1998).

For the valuation of avoided hospital admissions, the current literature provides well-developed and detailed cost estimates of hospitalization by health effect or illness. Using illness-specific estimates of avoided medical costs and avoided costs of lost work-time that Elixhauser (1993) developed, we construct COI estimates specific to the suite of health effects defined by each C-R function. For example, we use twelve distinct C-R functions to quantify the expected change in respiratory admissions. Consequently in this analysis, we develop twelve separate COI estimates, each reflecting the unique composition of health effects considered in the individual studies. Details of the derivation of the values of avoided hospital admissions for respiratory and cardiovascular illnesses and asthma-related ER visits are provided in the benefits TSD for this RIA (Abt Associates, 1999).

11.7.3.9 Other Health Effects: Quantification

As indicated in Table 11-1, in addition to mortality, chronic illness, and hospital admissions, there are a number of acute health effects not requiring hospitalization that are associated with exposure to ambient levels of ozone and PM. The sources for the C-R functions used to quantify these effects are described below. A more complete description of these estimates is provided in the benefits TSD for this RIA (Abt Associates, 1999).

Around five percent of U.S. children between ages five and seventeen experience episodes of acute bronchitis annually (Adams, et al., 1995). Acute bronchitis is characterized by coughing, chest discomfort, and extreme tiredness. Incidences of acute bronchitis in children between the ages of five and seventeen are estimated using a C-R function developed from Dockery et al. (1996).

Incidences of lower respiratory symptoms (i.e., wheezing, deep cough) in children aged seven to fourteen are estimated using a C-R function developed from Schwartz et al. (1994). Because asthmatics have greater sensitivity to stimuli (including air pollution), children with asthma can be more susceptible to a variety of upper respiratory symptoms (i.e., runny or stuffy nose; wet cough; and burning, aching, or red eyes). Incidences of upper respiratory symptoms in asthmatic children aged nine to eleven are estimated using a C-R function developed from Pope et al. (1991).

Health effects from air pollution can also result in missed days of work (either from personal symptoms or from caring for a sick family member). Work loss days are estimated using a C-R function developed from Ostro (1987).

The endpoint minor restricted activity days (MRAD), which is also represented by the occurrence of any of 19 acute respiratory symptoms as defined by Krupnick et al. (1990), is a pooled estimate using estimates of C-R functions derived from Ostro and Rothschild (1989) and Krupnick et al. (1990).

As noted above, asthma affects over seven percent of the U.S. population. Air pollution is sometimes linked to development of asthma and occurrences of asthma symptoms (McDonnell, et al, 1999; Ostro, et al., 1991; Whittemore and Korn, 1980). Incidences of shortness of breath (in African American asthmatics[10]) are estimated using a C-R function derived from Ostro, et al. (1995). Other asthma related symptoms are included in the incidences of MRAD and any of 19 acute respiratory symptoms. Inclusion of separate estimates for these endpoints would result in double-counting of these benefits. Supplemental calculations for separate asthma only endpoints are included in Appendix A.

In addition to the health effects discussed above, human exposure to PM and ozone is believed to be linked to health effects such as ozone-related premature mortality (Ito and Thurston, 1996; Samet, et al. 1997), PM-related infant mortality (Woodruff, et al., 1997), cancer (U.S. EPA, 1996b), increased emergency room visits for non-asthma respiratory causes (U.S. EPA, 1996a; 1996b), impaired airway responsiveness (U.S. EPA, 1996a), increased susceptibility to respiratory infection (U.S. EPA, 1996a), acute inflammation and respiratory cell damage (U.S. EPA, 1996a), premature aging of the lungs and chronic respiratory damage (U.S. EPA, 1996a; 1996b). An improvement in ambient PM and ozone air quality may reduce the number of incidences within each effect category that the U.S. population would experience. Although these health effects are believed to be PM or ozone-induced, C-R data is not available for quantifying the benefits associated with reducing these effects. The inability to quantify these effects lends a downward bias to the monetized benefits presented in this analysis.

Another category of potential effects that may change in response to ozone strategies results from the shielding provided by ozone against the harmful effects of ultraviolet radiation (UV-B) derived from the sun. The great majority of this shielding results from naturally occurring ozone in the stratosphere, but the 10% of total “column” ozone present in the troposphere also contributes (NAS, 1991). A variable portion of this tropospheric fraction of UV-B shielding is derived from ground level or “smog” ozone related to anthropogenic air pollution. Therefore, strategies that reduce ground level ozone will, in some small measure, increase exposure to UV-B from the sun.

While it is possible to provide quantitative estimates of benefits associated with globally based strategies to restore the far larger and more spatially uniform stratospheric ozone layer, the changes in UV-B exposures associated with ground level ozone reduction strategies are much more

[10]Shortness of breath due to PM exposure is not necessarily limited to African-American asthmatics. However, the Ostro, et al. study was based on a sample of African-American children, who may be more sensitive to air pollution than the general population so we chose not to extrapolate the findings to the general population.

complicated and uncertain. Smog ozone strategies, such as mobile source controls, are focused on decreasing peak ground level ozone concentrations, and it is reasonable to conclude that they produce a far more complex and heterogeneous spatial and temporal pattern of ozone concentration and UV-B exposure changes than do stratospheric ozone protection programs. In addition, the changes in long-term total column ozone concentrations are far smaller from ground-level programs. To properly estimate the change in exposure and impacts, it would be necessary to match the spatial and temporal distribution of the changes in ground-level ozone to the spatial and temporal distribution of exposure to ground level ozone and sunlight. More importantly, it is long-term exposure to UV-B that is associated with effects. Intermittent, short-term, and relatively small changes in ground-level ozone and UV-B are not likely to measurably change long-term risks of these adverse effects.

For all of these reasons, we were unable to provide reliable estimates of the changes in UV-B shielding associated with ground-level ozone changes. This inability lends an upward bias to the net monetized benefits presented in this analysis. It is likely that the adverse health effects associated with increases in UV-b exposure from decreased tropospheric ozone will, however, be relatively small because 1) the expected long-term ozone change resulting from this rule is small relative to total anthropogenic tropospheric ozone, which in turn is small in comparison to total column natural stratospheric and tropospheric ozone; 2) air quality management strategies are focused on decreasing peak ozone concentrations and thus may change exposures over limited areas for limited times, 3) people often receive peak exposures to UV-B in coastal areas where sea or lake breezes reduce ground level pollution concentrations regardless of strategy, and 4) ozone concentration changes are greatest in urban areas and areas immediately downwind of urban areas. In these areas, people are more likely to spend most of their time indoors or in the shade of buildings, trees or vehicles.

11.7.3.10 Other Health Effects: Valuation

The valuation of a specific short-term morbidity endpoint is generally estimated by representing the illness as a cluster of acute symptoms. For each symptom, the WTP is calculated. These values, in turn, are aggregated to arrive at the WTP to avoid a specific short term condition. For example, the endpoint lower respiratory symptoms (LRS) is represented by two or more of the following symptoms: runny or stuffy nose; coughing; and eye irritation. The WTP to avoid one day of LRS is the sum of values associated with these symptoms. The primary advantage of this approach is that is provides some flexibility in constructing estimates to represent a variety of health effects.

Valuation estimates for individual minor health effects are listed in Table 11-4. Derivation of the individual valuation estimates is provided in the benefits TSD for this RIA. Mean estimates range from $5.30 for an avoided incidence of shortness of breath to $45 for an avoided incidence of acute bronchitis. The value of work loss days varies depending on the location of an affected population. Using the median daily wage, the value of a work loss day is $83.

11.7.3.11 Lost Worker Productivity: Quantification and Valuation

While not technically a health effect, lost worker productivity related to pollution exposure is presumably linked to reductions in the physical capabilities of workers in outdoor jobs. The value of lost worker productivity due to ozone exposure is directly estimated based on a study of California citrus workers (Crocker and Horst, 1981 and U.S. EPA, 1994). The study measured productivity impacts as the change in income associated with a change in ozone exposure, given as the elasticity of income with respect to ozone concentration (or the percentage change in income for a one percent change in ambient ozone concentration). The reported elasticity translates a ten percent reduction in ozone to a 1.4 percent increase in income.

11.7.4 Estimated Reductions in Incidences of Health Endpoints and Associated Monetary Values

Applying the C-R and valuation functions described above to the estimated changes in ozone and PM for the 2007 "Representative Year," the 2007 "SO_2 Increasing" and the 2004 "SO_2 Decreasing" scenarios yields estimates of the number of avoided incidences (i.e., premature mortalities, cases, admissions, etc.) and the associated monetary values for those avoided incidences. These estimates are presented in Tables 11-6 and 11-7. All of the monetary benefits are in constant 1997 dollars.

Time constraints prevented us from estimating the changes in ambient ozone resulting from the final Section 126 rule for inclusion in this volume of the RIA. As a result, we are unable to provide quantified or monetized estimates of the reductions in incidences of ozone-related health effects. These unmonetized benefits are indicated by place holders, labeled B_1 to B_9. Unquantified physical effects are indicated by a U. The estimate of total monetized health benefits is thus equal to the subset of monetized PM health benefits plus $\mathbf{B_H}$, the sum of the unmonetized health benefits.

The largest monetized health benefit is associated with reductions in the risk of premature mortality. The next largest benefit is for chronic bronchitis reductions, although this value is more than an order of magnitude lower than for premature mortality. The remaining categories account for less than $10 million each, however, they represent a large number of avoided incidences affecting many individuals.

Total monetized health related benefits for the "Representative Year" scenario (sulfates held constant) are around $1.1 billion. When sulfates are allowed to increase in the 2007 "SO_2 increasing" scenario, benefits are reduced by over seventy percent, to $300 million, highlighting the importance of SO_2 emissions as precursors to PM formation. In a similar manner, the 2004 "SO_2 decreasing" scenario results in an increase in total health related benefits of over seventy percent, to $1.9 billion.

Alternative calculations for premature mortality incidences and valuation are presented in Table 11-16 in section 11.9 of this chapter. An alternative calculation is also provided in that table for chronic bronchitis incidences.

Table 11-6.
Estimated Annual Health Benefits Associated With Air Quality Changes Resulting from the Final Section 126 Rule in 2007 for the "Representative Year" Scenario

Endpoint	Avoided Incidence (cases/year)	Monetary Benefits (millions 1997$)
PM-related Health Effects		
Premature mortality[a]	200	$1,090
Chronic bronchitis	110	$30
Hospital Admissions from Respiratory Causes	50	$<5
Hospital Admissions from Cardiovascular Causes	20	$<1
Emergency Room Visits for Asthma	40	$<1
Acute bronchitis	350	$<1
Lower respiratory symptoms (LRS)	3,830	$<1
Upper respiratory symptoms (URS)	3,880	$<1
Shortness of breath	970	$<1
Work loss days (WLD)	29,910	$<5
Minor restricted activity days (MRAD)/Acute respiratory symptoms	159,730	$10
Other PM-related health effects	U_1	B_1
Ozone-related Health Effects		
Chronic asthma	U_2	B_2
Hospital Admissions from Respiratory Causes	U_3	B_3
Hospital Admissions from Cardiovascular Causes	U_4	B_4
Emergency Room Visits for Asthma	U_5	B_5
Minor restricted activity days/Acute respiratory symptoms	U_6	B_6
Decreased worker productivity	—	B_7
Other ozone-related health effects	U_8	B_8
Total Monetized Health-related Benefits[b]	—	$1,139+$\mathbf{B_H}$

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope, et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] $\mathbf{B_H}$ is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_9$.

Table 11-7.
Estimated Annual Health Benefits Associated With Air Quality Changes Resulting from the Final Section 126 Rule for the Alternative "SO_2 Increasing" and "SO_2 Decreasing" Scenarios

Endpoint	"SO_2 Increasing" Scenario		"SO_2 Decreasing" Scenario	
	Avoided Incidence[b] (cases/year)	**Monetary Benefits[c] (millions 1997$)**	**Avoided Incidence[b] (cases/year)**	**Monetary Benefits[c] (millions 1997$)**
PM-related Health Effects				
Premature mortality[a]	50	$290	340	$1,830
Chronic bronchitis	30	$10	170	$60
Hospital Admissions from Respiratory Causes	20	$<1	80	$<5
Hospital Admissions from Cardiovascular Causes	10	$<1	40	$<5
Emergency Room Visits for Asthma	10	$<1	70	$<1
Acute bronchitis	100	$<1	560	$<1
Lower respiratory symptoms (LRS)	1,050	$<1	6,700	$<1
Upper respiratory symptoms (URS)	1,180	$<1	6,120	$<1
Shortness of breath	300	$<1	1,210	$<1
Work loss days (WLD)	9,020	$<5	61,480	$10
Minor restricted activity days/Acute resp. symptoms	48,180	$<5	265,230	$10
Other PM-related health effects	U_1	B_1	U_1	B_1
Ozone-related Health Effects				
Chronic asthma	U_2	B_2	U_2	B_2
Hospital Admissions from Respiratory Causes	U_3	B_3	U_3	B_3
Hospital Admissions from Cardiovascular Causes	U_4	B_4	U_4	B_4
Emergency Room Visits for Asthma	U_5	B_5	U_5	B_5
Minor restricted activity days/Acute resp. symptoms	U_6	B_6	U_6	B_6
Decreased worker productivity	—	B_7	—	B_7
Other Ozone-related health effects	U_8	B_8	U_8	B_8
Total Monetized Health-related Benefits[c]	—	$300+**B_H**$	—	$1,900+**B_H**$

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope, et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] The U_i are the incidences for the unquantified category i.
[c] $\mathbf{B_H}$ is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_9$.

11.8 Assessment of Human Welfare Benefits

Particulate matter and ozone have numerous documented effects on environmental quality that affect human welfare. These welfare effects include direct damages to property, either through impacts on material structures or by soiling of surfaces, direct economic damages in the form of lost productivity of crops and trees, indirect damages through alteration of ecosystem functions, and indirect economic damages through the loss in value of recreational experiences or the existence value of important resources. EPA's criteria documents for ozone and PM list numerous physical and ecological effects known to be linked to ambient concentrations of these pollutants (U.S. EPA, 1996a, 1996b). This section describes individual effects and how we quantify and monetize them. These effects include changes in crop yields, visibility, and nitrogen deposition to estuaries.

Section 11.8.1 describes how we quantify and value changes in visibility, both in federal Class I areas (national parks and wilderness areas) and in the areas where people live and work. In section 11.8.2 we describe how we value the benefits of increased agricultural and commercial forest yields resulting from decreased levels of ambient ozone. In section 11.8.3 we describe the damage to materials caused by particulate matter. In section 11.8.4 we discuss the effects of nitrogen deposition on estuaries and describe how we quantify changes in nitrogen loadings. Section 11.8.5 includes a summary of the monetized estimates for welfare effects.

11.8.1 Visibility Benefits

Changes in the level of ambient PM caused by the final Section 126 rule will change the level of visibility in much of the Eastern U.S. Visibility directly affects people's enjoyment of a variety of daily activities. Individuals value visibility both in the places they live and work, in the places they travel to for recreational purposes, and at sites of unique public value, such as the Grand Canyon. This section discusses the measurement of the economic benefits of visibility.

It is difficult to quantitatively define a visibility endpoint that can be used for valuation. Increases in PM concentrations cause increases in light extinction. Light extinction is a measure of how much the components of the atmosphere absorb light. More light absorption means that the clarity of visual images and visual range is reduced, *ceteris paribus*. Light absorption is a variable that can be accurately measured. Sisler (1996) created a unitless measure of visibility based directly on the degree of measured light absorption called the *deciview*. Deciviews are standardized for a reference distance in such a way that one deciview corresponds to a change of about 10 percent in available light. Sisler characterized a change in light extinction of one deciview as "a small but perceptible scenic change under many circumstances." Air quality models were used to predict the change in visibility, measured in deciviews, of the areas affected by the final Section 126 rule (Chapter 10)[11].

EPA considers benefits from two categories of visibility changes: residential visibility and recreational visibility. In both cases economic benefits are believed to consist of both use values and non-use values. The use values include the aesthetic benefits of better visibility, improved road and air safety, and enhanced recreation in activities like hunting and birdwatching. The non-use values are based on people's beliefs that the visibility in national parks and in the places they live and work ought to exist free of human-induced impairment. Non-use values may be a more important component of value for recreational areas, particularly national parks and monuments.

Residential visibility benefits are those that occur from visibility changes in urban, suburban, and rural areas, and also in recreational areas **not** listed as federal Class I areas[12]. Recreational visibility improvements are those that occur specifically in federal Class I areas. A key distinction is that only those people living in residential areas are assumed to receive benefits from residential visibility, while all households in the U.S. are assumed to derive some benefit from improvements in Class I areas. Values are assumed to be higher if the Class I area is located close to their home.[13]

The results of air quality modeling for the final Section 126 rule for the "Representative Year" scenario show small improvements in visibility in all areas of the Eastern U.S. The mean improvement across all counties in the study area was 0.02 deciviews. The biggest improvements in visibility were most often found in heavily populated urban areas. Of the counties with more than one million in population in 2007, 22 percent show an improvement of 0.05 deciviews or more. For the 22 percent of metropolitan areas showing an improvement of 0.05 deciviews or more, the baseline visibility is 23.5.

Only two existing studies provide defensible monetary estimates of the value of visibility changes. One is a study on residential visibility conducted in 1990 (McClelland, et. al., 1993) and the other is a 1988 survey on recreational visibility value (Chestnut and Rowe, 1990a, 1990b). Both utilize the contingent valuation method. There has been a great deal of controversy and significant development of both theoretical and empirical knowledge about how to conduct CVM surveys in the past decade. In EPA's judgment, the Chestnut and Rowe study contains many of the elements of a

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[11]A change of less than 10 percent in the light extinction budget represents a measurable improvement in visibility, but may not be perceptible to the eye in many cases. Some of the average regional changes in visibility are less than one deciview (i.e. less than 10 percent of the light extinction budget), and thus less than perceptible. However, this does not mean that these changes are not real or significant. Our assumption is then that individuals can place values on changes in visibility that may not be perceptible. This is quite plausible if individuals are aware that many regulations lead to small improvements in visibility which when considered together amount to perceptible changes in visibility.

[12] The Clean Air Act designates 156 national parks and wilderness areas as Class I areas for visibility protection.

[13] For details of the visibility benefits estimates, please refer to the benefits TSD for this RIA (Abt Associates, 1999b).

valid CVM study and is sufficiently reliable to serve as the basis for monetary estimates of the benefits of visibility changes in recreational areas[14]. This study serves as an essential input to our estimates of the benefits of recreational visibility improvements in the primary benefits estimates. Based on SAB advice (EPA-SAB-COUNCIL-ADV-00-002, 1999), EPA has designated the McClelland et al. study as significantly less reliable for regulatory benefit-cost analysis, but it does provide useful estimates on the order of magnitude of residential visibility benefits. Residential visibility benefits are therefore only included as an alternative calculation in Table 11-16. The methodology for this alternative calculation, explained below, is similar to the procedure for recreational benefits.

Chestnut and Rowe measured the demand for visibility in Class I areas managed by the National Park Service (NPS) in three broad regions of the country: California, the Southwest, and the Southeast. For this analysis, only the results for southeastern parks were used to infer benefits[15]. Respondents in five states were asked about their WTP to protect visibility in national parks or NPS-managed wilderness areas within a particular region. The survey used photographs reflecting different visibility levels in the specified recreational areas. The visibility levels in these photographs were later converted to deciviews for the current analysis. The survey data collected were used to estimate a willingness-to-pay equation for improved visibility. In addition to the visibility change variable, the estimating equation also included household income as an explanatory variable.

The estimated relationship from the Chestnut and Rowe study is only directly applicable to the populations represented by survey respondents. EPA used benefits transfer methodology to extrapolate these results to the population affected by the final Section 126 rule. A general WTP equation for improved visibility (measured in deciviews) was developed as a function of the baseline level of visibility, the magnitude of the visibility improvement, and household income. The behavioral parameters of this equation were taken from an analysis of the Chestnut and Rowe data. These parameters were used to calibrate WTP for the visibility changes resulting from the final Section 126 rule. The method for developing calibrated WTP functions is based on the approach developed by Smith et al. (1999). Available evidence indicates that households are willing to pay more for a given visibility improvement as their income increases (Chestnut, 1997). The benefits estimates here incorporate Chestnut's estimate that a 1 percent increase in income is associated with a 0.9 percent increase in WTP for a given change in visibility.

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[14] An SAB advisory letter (EPA-SAB-COUNCIL-ADV-00-002, 1999) indicates that "many members of the Council believe that the Chestnut and Rowe study is the best available," however, the council did not formally approve use of these estimates because of concerns about the peer-reviewed status of the study. EPA believes the study has received adequate review and has been cited in numerous peer-reviewed publications (Chestnut and Dennis, 1997).

[15] Because the Section 126 rule affects only states in the OTAG region, no Class I areas in California or the Southwest are impacted by the rule. There are Class I areas in the OTAG region which were not examined in the Chestnut and Rowe study. We can infer the value of visibility changes in these Class I areas by transferring values of visibility changes at Class I areas in the Southeast. However, these values are not as defensible and are thus presented only as an alternative calculation in Table 11-16. A complete description of the benefits transfer method used to infer values for visibility changes in Class I areas outside the Southeast is provided in the benefits TSD for this RIA (Abt Associates, 1999).

Using the methodology outlined above, EPA estimates that the total WTP for the visibility improvements in Class I areas brought about by the final Section 126 rule is $41 million for the "Representative Year" scenario. This number includes the value to households living in the same state as the Class I area as well as values to all households in the U.S. living outside the state containing the Class I area. A complete presentation of this method can be found in the benefits TSD for this RIA (Abt Associates, 1999).

One major source of uncertainty for the visibility benefit estimate is the benefits transfer process used. Judgments used to choose the functional form and key parameters of the estimating equation for WTP for the affected population could have significant effects on the size of the estimates. Assumptions about how individuals respond to changes in visibility that are either very small, or outside the range covered in the Chestnut and Rowe study, could also affect the results.

11.8.2 Agricultural and Forestry Benefits

Reduced levels of ground-level ozone resulting from the final Section 126 rule will have generally beneficial results on agricultural crop yields and commercial forest growth. Well-developed techniques exist to provide monetary estimates of these benefits to agricultural producers and to consumers. These techniques use models of farmers' planting decisions, yield response functions, and agricultural supply and demand. The resulting welfare measures are based on predicted changes in market prices and production costs.

The economic value associated with varying levels of yield loss for ozone-sensitive commodity crops is analyzed using the AGSIM© agricultural benefits model (Taylor et al., 1993). AGSIM© is an econometric-simulation model based on a large set of statistically estimated demand and supply equations for agricultural commodities produced in the United States. The model is capable of analyzing the effects of changes in policies (in this case, the implementation of the final Section 126 rule) that affect commodity crop yields or production costs. The benefits TSD for this RIA also provides further details on AGSIM© (Abt Associates, 1999).

The measure of benefits calculated by the model is the net change in consumer and producer surplus from baseline ozone concentrations to the ozone concentrations resulting from implementation of the final Section 126 rule. Using the baseline and post-control equilibria, the model calculates the change in net consumer and producer surplus on a crop-by-crop basis[16]. Dollar values are aggregated across crops for each standard. The total dollar value represents a measure of the change in social welfare associated with the final Section 126 rule.

[16] Agricultural benefits differ from other health and welfare endpoints in the length of the assumed ozone season. For agriculture, the ozone season is assumed to extend from April to September. This assumption is made to ensure proper calculation of the ozone statistic used in the exposure-response functions. The only crop affected by changes in ozone during April is winter wheat.

The model employs biological exposure-response information derived from controlled experiments conducted by the National Crop Loss Assessment Network (NCLAN, 1996). For the purpose of our analysis, we analyze changes for the six most economically significant crops for which dose-response functions are available: corn, cotton, peanuts, sorghum, soybean, and winter wheat.[17] Time constraints prevented us from including these estimates in this volume of the RIA. However, agricultural benefits will be provided in a supplementary volume.[18]

Similar models exist for forest products. Ozone also has been shown conclusively to cause discernible injury to forest trees (Fox and Mickler, 1996). Once the effects of changes in ozone concentrations on tree growth are predicted, econometric models of forest product supply and demand can be used to estimate changes in prices, producer profits and consumer surplus. EPA did not have predicted levels of ozone changes from the 126 rule in time to provide quantitative estimates of forestry benefits for this analysis.[19] An additional welfare benefit expected to accrue as a result of reductions in ambient ozone concentrations in the United States is the economic value the public receives from reduced aesthetic injury to forests. There is sufficient scientific information available to reliably establish that ambient ozone levels cause visible injury to foliage and impair the growth of some sensitive plant species (U.S. EPA, 1996c, p. 5-521). However, present analytic tools and resources preclude EPA from quantifying the benefits of improved forest aesthetics.

Urban ornamentals represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels and likely to impact large economic sectors. In the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative economic benefits analysis has been conducted. It is estimated that more than $20 billion (1990 dollars) are spent annually on landscaping using ornamentals (Abt Associates, 1995), both by private property owners/tenants and by governmental units responsible for public areas. This is therefore a potentially important welfare effects category. However, information and valuation methods are not available to allow for plausible estimates of the percentage of these expenditures that may be related to impacts associated with ozone exposure.

The final Section 126 rule, by reducing NO_X emissions, will also reduce nitrogen deposition on agricultural land and forests. There is some evidence that nitrogen deposition may have positive effects on agricultural output through passive fertilization. Holding all other factors constant, farmers' use of purchased fertilizers or manure may increase as deposited nitrogen is reduced. Estimates of the potential value of this possible increase in the use of purchased fertilizers are not available, but it is likely that the overall value is very small relative to other health and welfare effects. The share of nitrogen requirements provided by this deposition is

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[17] The total value for these crops in 1997 was $57 billion.

[18] For comparison, EPA conducted an analysis of agricultural benefits for the NO_X SIP Call and found annual benefits of between $54 and $640 million (1997$).

[19] For comparison, EPA conducted an analysis of commercial forestry benefits for the NO_X SIP Call and found annual benefits of $262 million (1997$).

small, and the marginal cost of providing this nitrogen from alternative sources is quite low. In some areas, agricultural lands suffer from nitrogen over-saturation due to an abundance of on-farm nitrogen production, primarily from animal manure. In these areas, reductions in atmospheric deposition of nitrogen from PM represent additional agricultural benefits.

Information on the effects of changes in passive nitrogen deposition on forests and other terrestrial ecosystems is very limited. The multiplicity of factors affecting forests, including other potential stressors such as ozone, and limiting factors such as moisture and certain nutrients, confound assessments of marginal changes in any one stressor or limiting factor in forest ecosystems. However, reductions in deposition of nitrogen could have negative effects on forest and vegetation growth in ecosystems where nitrogen is a limiting factor (U.S. EPA, 1993).

On the other hand, there is evidence that forest ecosystems in some areas of the U.S. are nitrogen saturated (U.S. EPA, 1993). Once saturation is reached, adverse effects of additional nitrogen begin to occur. One adverse effect, soil acidification, can lead to the leaching of nutrients needed for plant growth and the mobilization of harmful elements such as aluminum. Increased soil acidification is also linked to higher amounts of acidic runoff to streams and lakes and leaching of harmful elements into aquatic ecosystems.

11.8.3 Benefits from Reductions in Materials Damage

The final Section 126 rule is expected to produce economic benefits in the form of reduced materials damage. There are two important categories of these benefits. Household soiling refers to the accumulation of dirt, dust, and ash on exposed surfaces. Criteria pollutants also have corrosive effects on commercial/industrial buildings and structures of cultural and historical significance. The effects on historic buildings and outdoor works of art are of particular concern because of the uniqueness and irreplaceability of many of these objects.

Previous EPA benefit analyses have been able to provide quantitative estimates of household soiling damage. Following an SAB recommendation (EPA-SAB-Council-ADV-003, 1998), EPA has determined that the existing data (based on consumer expenditures from the early 1970's) is too out of date to provide a reliable enough estimate of current household soiling damages. However, a calculation is made for inclusion in the alternative calculations table (Table 11-16).

EPA is unable to estimate any benefits to commercial and industrial entities from reduced materials damage. Nor is EPA able to estimate the benefits of reductions in PM-related damage to historic buildings and outdoor works of art. Existing studies of damage to this latter category in Sweden (Grosclaude and Soguel, 1994) indicate that these benefits could be an order of magnitude larger than household soiling benefits.

11.8.4 Benefits from Reduced Ecosystem Damage

The effects of air pollution on the health and stability of ecosystems are potentially very important, but at present are poorly understood and difficult to measure. The reductions in NOx caused by the final rule could produce significant benefits. Excess nutrient loads, especially of nitrogen, cause a variety of adverse consequences to the health of estuarine and coastal waters. These effects include toxic and/or noxious algal blooms such as brown and red tides, low (hypoxic) or zero (anoxic) concentrations of dissolved oxygen in bottom waters, the loss of submerged aquatic vegetation due to the light-filtering effect of thick algal mats, and fundamental shifts in phytoplankton community structure (Haire et al., 1992).

Reductions in nitrogen loadings are estimated for twelve eastern estuaries (including two on the the Gulf Coast). These estimated reductions are described in Chapter 10. Four of these estuaries have established consensus goals for reductions in annual nitrogen loads, indicating an intention of reaching these goals through implementation of controls on nitrogen sources. These four estuaries and their reduction goals are listed in Table 11-8.

Table 11-8
Reduction Goals and Nitrogen Loads to Selected Eastern Estuaries
(tons per year)

Estuary	Total Nitrogen Loadings	Nitrogen Loadings from Atmospheric Deposition	Overall Reduction Goal
Albemarle/Pamlico Sound	25,300	11,000	7,600
Chesapeake Bay	185,000	49,500	35,600
Long Island Sound	53,700	13,200	31,460
Tampa Bay	3,900	2,100	100

Source: U.S. EPA, 1998b

Estimated reductions in deposition of atmospheric nitrogen to these four estuaries are listed in Table 11-9, along with the percentage of the reduction goal accounted for by these reductions. Estimates of nitrogen deposition are not affected by emissions of SO_2. As such, nitrogen deposition will be the same in all three of the SO_2 emission banking scenarios. These figures suggest that the reductions in nitrogen deposition resulting from the final Section 126 rule will provide significant progress towards meeting nitrogen reduction goals in several of these estuaries.

Table 11-9
Estimated Reductions in 2007 in Nitrogen Loadings in Selected Eastern Estuaries for the Final Section 126 Rule
(tons per year)

Estuary	Change in Nitrogen Loadings	% of Estuary Nitrogen Reduction Goal
Albemarle/Pamlico Sound	-1,639	21.6%
Chesapeake Bay	-4,851	13.6%
Long Island Sound	-451	1.4%
Tampa Bay	-99	99.0%

Direct C-R functions relating changes in nitrogen loadings to changes in estuarine benefits are not available. The preferred WTP based measure of benefits depends on the availability of these C-R functions and on estimates of the value of environmental responses. Because neither appropriate C-R functions nor sufficient information to estimate the marginal value of changes in water quality exist at present, calculation of a WTP measure is not possible. As stated earlier, an alternative is to use an avoided cost approach to estimate the welfare effects of PM on estuarine ecosystems. The use of the avoided cost approach to establish the value of a reduction in nitrogen deposition is problematic if there is not a direct link between reductions in air deposited nitrogen and the abandonment of a costly regulatory program. However, there are currently no readily available alternatives to this approach.

Based on the advice of the EPA Science Advisory Board, we use the avoided cost approach only to derive an alternative calculation of the value of reductions in atmospheric nitrogen loadings to estuaries (EPA-SAB-COUNCIL-ADV-00-002, 1999). The SAB believes that the avoided cost approach for nitrogen loadings is valid only if the state and local governments have established firm pollution reduction targets, and that displaced costs measured in the study represent measures not taken because of the CAAA (EPA-SAB-COUNCIL-ADV-00-002, 1999). Because the nitrate reduction targets in the studied estuaries are not firm targets, and there is not assurance that planned measures would be undertaken in the absence of the CAAA, we are currently unable to provide a meaningful primary estimate. However, the avoided cost estimate is presented in the table of alternative calculations (Table 11-16).

If better models of ecological effects can be defined, EPA believes that progress can be made in estimating WTP measures for ecosystem functions. These estimates would be superior to avoided cost estimates in placing economic values on the welfare changes associated with air pollution damage to ecosystem health. For example, if nitrogen or sulfate loadings can be linked to measurable and definable changes in fish populations or definable indices of biodiversity, then CVM studies can be designed to elicit individuals' willingness to pay for changes in these effects. This is an important area for further research and analysis, and will require close collaboration among air quality modelers, natural scientists, and economists.

11.8.5 Estimated Values for Welfare Endpoints

Applying the valuation methods described above to the estimated changes in ozone and PM for the 2007 "Representative Year," the 2007 "SO_2 Increasing" and the 2004 "SO_2 Decreasing" scenarios yields estimates of the value of changes in visibility and agricultural yields. These estimates are presented in Tables 11-10 and 11-11 . All of the monetary benefits are in constant 1997 dollars.

Time constraints prevented us from estimating the changes in ambient ozone resulting from the final Section 126 rule for inclusion in this volume of the RIA. As a result, we are unable to provide monetized estimates of the value of increased crop yields or increased commercial forest productivity. In addition, we are unable to provide primary monetized estimates of residential visibility, household soiling, materials damage, and nitrogen deposition benefits. These unmonetized benefits are indicated by place holders, labeled B_{10} to B_{17}. The estimate of total monetized welfare benefits is thus equal to the subset of monetized welfare benefits plus $\mathbf{B_W}$, the sum of the unmonetized welfare benefits. Alternative calculations for recreational visibility, residential visibility, household soiling, and nitrogen deposition are presented in Table 11-16 in section 11.9 of this chapter.

Total monetized welfare related benefits for the "Representative Year" scenario (sulfates held constant) are approximately $40 million. When sulfates are allowed to increase in the 2007 "SO_2 increasing" scenario, benefits are reduced by around fifty percent, to $20 million. The 2004 "$SO_2$ decreasing" scenario results in total welfare related benefits of around $40 million, similar to that for the "Representative Year" scenario. The only monetized welfare category for this analysis is recreational visibility. This category is based on changes in visibility at only twelve counties in the Southeastern U.S. with Class I areas. As such, the benefits for this category may be less sensitive to changes in SO_2 than other benefit categories. Our results suggest that decreases in sulfates have little impact on the Class I areas, while increases had a much larger effect, due to differences in the distribution of those changes. For all scenarios, monetized welfare benefits are roughly one-twentieth the magnitude of monetized health benefits. However, due to the difficulty in quantifying and monetizing welfare benefits, a higher proportion of welfare benefits are not monetized. Thus, it would be inappropriate to conclude that welfare benefits are unimportant just by comparing them to monetized health benefits.

Table 11-10.
Estimated Welfare Benefits Associated With Improved Air Quality Resulting from the Final Section 126 Rule in 2007 for the "Representative Year" Scenario

Endpoint	Monetary Benefits (millions 1997$)
PM-related Welfare Effects	
Recreational Visibility (18 Southeastern Class I areas)	\$41
Residential Visibility	B_{10}
Household Soiling	B_{11}
Materials Damage	B_{12}
Nitrogen Deposition to Eastern Estuaries	B_{13}
Other PM-related Welfare Effects	B_{14}
Ozone-related Welfare Effects	
Commercial Agricultural Benefits (6 major crops)	B_{15}
Commercial Forestry Benefits	B_{16}
Other Ozone-related Welfare Effects	B_{17}
Total Monetized Welfare-related Benefits[a]	\$41+$\mathbf{B_W}$

[a] $\mathbf{B_W}$ is equal to the sum of all unmonetized categories, i.e. $B_8+B_9+...+B_{13}$.

Table 11-11.
Estimated Welfare Benefits Associated With Improved Air Quality Resulting from the Final Section 126 Rule in 2007 for the Alternative "SO_2 Increasing" and "SO2 Decreasing" Scenarios

Endpoint	*Monetary Benefits (millions 1997$)*	
	"SO2 Increasing" Scenario	*"SO2 Decreasing" Scenario*
PM-related Welfare Effects		
Recreational Visibility (18 Southeastern Class I areas)	$22	$36
Residential Visibility	B_{10}	B_{10}
Household Soiling	B_{11}	B_{11}
Materials Damage	B_{12}	B_{12}
Nitrogen Deposition to Eastern Estuaries	B_{13}	B_{13}
Other PM-related Welfare Effects	B_{14}	B_{14}
Ozone-related Welfare Effects		
Commercial Agricultural Benefits (6 major crops)	B_{15}	B_{15}
Commercial Forestry Benefits	B_{16}	B_{16}
Other Ozone-related Welfare Effects	B_{17}	B_{17}
Total Monetized Welfare-related Benefits[a]	$22+$\mathbf{B_W}$	$36+$\mathbf{B_W}$

[a] $\mathbf{B_W}$ is equal to the sum of all unmonetized welfare categories, i.e. $B_{10}+B_{11}+...+B_{17}$.

11.9 Total Benefits

We provide our preferred estimate of benefits for each health and welfare endpoint and the resulting preferred estimate of total benefits. To obtain this estimate, we aggregate dollar benefits associated with each of the effects examined into a total benefits estimate assuming none of the included health and welfare effects overlap. The point estimate of the total benefits associated with the health and welfare effects is the sum of the separate effects estimates. Total monetized benefits associated with the final Section 126 rule for the "Representative Year" are presented in Table 11-12 along with a breakdown of benefits by endpoint. The results of sensitivity analyses for the 2007 "SO_2 Increasing" and the 2004 "SO_2 Decreasing" scenarios are listed in Tables 11-14 and 11-15[20]. Note that the values of endpoints known to be affected by

[20] A full description of the "Representative Year," the 2007 "SO_2 Increasing" and the 2004 "SO_2 Decreasing" scenarios can be found in Chapter 9. The "Representative Year" scenario holds sulfate concentration constant to reflect the long-term cap on SO_2 emissions which should result in no change in SO_2 emissions over the full analytical time period. The "SO_2 Increasing" scenario allows for the full range of air quality response to predicted SO_2 increases in 2007 due to banking and trading. The "SO_2 Decreasing" scenario examines a year

ozone and/or PM that we are not able to monetize are assigned a placeholder value, e.g. B_1, B_2, etc. Unquantified physical effects are indicated by a U. The estimate of total benefits is thus the sum of the monetized benefits and a constant, **B**, equal to the sum of the unmonetized benefits, $B_1+B_2+...+B_n$.

A comparison of the incidence columns to the monetary benefits columns reveals that there is not always a close correspondence between the number of incidences avoided for a given endpoint and the monetary value associated with that endpoint. This reflects the fact that many of the less severe health effects, while more common, are valued at a lower level than the more severe health effects. This is, in fact, consistent with economic theory, which suggests that the value of a health effect should increase with the impact on an individual's utility.

Total monetized benefits in these scenarios are dominated by the benefits of reduced mortality risk. Mortality related benefits account for over 85 percent of total monetized benefits in all scenarios, followed by chronic bronchitis (3 percent).

However, the adoption of a value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economic and public policy analysis community within and outside the Administration. In response to the sensitivity on this issue, we provide estimates reflecting two alternative approaches. The first approach -- supported by some in the above community and preferred by EPA -- uses a Value of a Statistical Life (VSL) approach developed for the Clean Air Act Section 812 benefit-cost studies. This VSL estimate of $5.9 million (1997$) was derived from a set of 26 studies identified by EPA using criteria established in Viscusi (1992), as those most appropriate for environmental policy analysis applications.

An alternative, age-adjusted approach is preferred by some others in the above community both within and outside the Administration. This approach was also developed for the Section 812 studies and addresses concerns with applying the VSL estimate –reflecting a valuation derived mostly from labor market studies involving healthy working-age manual laborers– to PM-related mortality risks that are primarily associated with older populations and those with impaired health status. This alternative approach leads to an estimate of the value of a statistical life year (VSLY), which is derived directly from the VSL estimate. It differs only in incorporating an explicit assumption about the number of life years saved and an implicit assumption that the valuation of each life year is not affected by age.[21] The mean VSLY is $360,000 (1997$); combining this number with a mean life expectancy of 14 years yields an age-adjusted VSL of $3.6 million (1997$).

(2004) when SO_2 emissions are predicted to decrease relative to the baseline, due to banking of SO_2 permits.

[21] Specifically, the VSLY estimate is calculated by amortizing the $5.9 million mean VSL estimate over the 35 years of life expectancy associated with subjects in the labor market studies. The resulting estimate, using a 5 percent discount rate, is $360,000 per life-year saved in 1997 dollars. This annual average value of a life-year is then multiplied times the number of years of remaining life expectancy for the affected population (in the case of PM-related premature mortality, the average number of $ life-years saved is 14.

Both approaches are imperfect, and raise difficult methodological issues which are discussed in depth in the recently published Section 812 Prospective Study, the draft EPA Economic Guidelines, and the peer-review commentaries prepared in support of each of these documents. For example, both methodologies embed assumptions (explicit or implicit) about which there is little or no definitive scientific guidance. In particular, both methods adopt the assumption that the risk versus dollars trade-offs revealed by available labor market studies are applicable to the risk versus dollar trade-offs the general population would make in an air pollution context.

EPA currently prefers the VSL approach because, essentially, the method reflects the direct, application of what EPA considers to be the most reliable estimates for valuation of premature mortality available in the current economic literature. While there are several differences between the labor market studies EPA uses to derive a VSL estimate and the particulate matter air pollution context addressed here, those differences in the affected populations and the nature of the risks imply both upward and downward adjustments. For example, adjusting for age differences may imply the need to adjust the $5.9 million VSL downward as would adjusting for health differences, but the involuntary nature of air pollution-related risks and the lower level of risk-aversion of the manual laborers in the labor market studies may imply the need for upward adjustments. In the absence of a comprehensive and balanced set of adjustment factors, EPA believes it is reasonable to continue to use the $5.9 million value while acknowledging the significant limitations and uncertainties in the available literature. Furthermore, EPA prefers not to draw distinctions in the monetary value assigned to the lives saved even if they differ in age, health status, socioeconomic status, gender or other characteristic of the adult population.

Those who favor the alternative, age-adjusted approach (i.e. the VSLY approach) emphasize that the value of a statistical life is not a single number relevant for all situations. Indeed, the VSL estimate of $5.9 million (1997 dollars) is itself the central tendency of a number of estimates of the VSL for some rather narrowly defined populations. When there are significant differences between the population affected by a particular health risk and the populations used in the labor market studies - as is the case here - they prefer to adjust the VSL estimate to reflect those differences. While acknowledging that the VSLY approach provides an admittedly crude adjustment (for age though not for other possible differences between the populations) they point out it has the advantage of yielding an estimate that is not presumptively biased. Proponents of adjusting for age differences using the VSLY approach fully concur that enormous uncertainty remains on both sides of this estimate - upwards as well as downwards - and that the populations differ in ways other than age (and therefore life expectancy). But rather than waiting for all relevant questions to be answered, they prefer a process of refining estimates by incorporating new information and evidence as it becomes available.

The estimates of benefits for the final Section 126 rule using the different approaches for premature mortality valuation are presented in Table 11-13. The VSL approach –the approach EPA prefers – yields a monetized benefit estimate of $1.2 billion. The alternative VSLY, age-adjusted approach yields total monetized benefits of $0.7 billion.

The final Section 126 rule is expected to affect populations in the eastern 37 continental states. Given a projected population in this region in 2007 of 220 million, per capita monetized benefits (using EPA's preferred estimates) are $5.37 for the "Representative Year" scenario, $1.50 for the "$SO_2$ Increasing" scenario and $8.50 for the "$SO_2$ Decreasing" scenario. Assuming an average household has 2.3 individuals, this amounts to $12.35 per household for the "Representative Year" scenario, $3.45 per household for the "SO_2 Increasing" scenario, and $19.55 per household for the "SO_2 Decreasing scenario.

Total monetized benefits (using EPA's preferred approach) for the worst case "SO2 Increasing" scenario (representing the largest expected increase in SO2 emissions for any year) are roughly one-third of those in the "Representative Year" scenario, and roughly one-sixth of those in the best case "SO2 Decreasing" scenario (representing the largest expected decrease in SO2 emissions for any year). Total monetized benefits for the "SO2 Decreasing" scenario are roughly 1.6 times those for the "Representative Year" scenario.

Table 11-12.
Estimated Annual Quantified and Monetized Benefits of the Final Section 126 Rule in 2007 for the "Representative Year" SO_2 Emissions Banking Scenario

Endpoint	Pollutant	Avoided Incidence[b] (cases/year)	Monetary Benefits[c] (millions 1997$)
Premature mortality[a,f] (adults, 30 and over)	PM	200	$1,090
Chronic asthma (adult males, 27 and over)	Ozone	U_2	B_2
Chronic bronchitis	PM	100	$30
Hospital Admissions from Respiratory Causes	Ozone and PM	$50+U_3$	$\$1+B_3$
Hospital Admissions from Cardiovascular Causes	Ozone and PM	$20+U_4$	$<\$1+B_4$
Emergency Room Visits for Asthma	Ozone and PM	$40+U_5$	$<\$1+B_5$
Acute bronchitis (children, 8-12)	PM	400	<$1
Lower respiratory symptoms (LRS) (children, 7-14)	PM	3,800	<$1
Upper respiratory symptoms (URS) (asthmatic children, 9-11)	PM	3,900	<$1
Shortness of breath (African American asthmatics, 7-12)	PM	1,000	<$1
Work loss days (WLD) (adults, 18-65)	PM	29,900	$3
Minor restricted activity days (MRAD)/Acute respiratory symptoms	Ozone and PM	$159{,}700+U_7$	$\$10+B_7$
Decreased worker productivity	Ozone	—	B_8
Other health effects	Ozone and PM	U_1+U_9	B_1+B_9
Recreational (Class I Area) visibility	PM and Gases	—	$40
Residential visibility	PM and Gases	—	B_{10}
Household soiling damage	PM	—	B_{11}
Materials damage	PM	—	B_{12}
Nitrogen Deposition	Nitrogen	—	B_{13}
Agricultural crop damage	Ozone	—	B_{15}
Commercial forest damage	Ozone	—	B_{16}
Other welfare effects	Ozone and PM	—	$B_{14}+B_{17}$
Monetized Total[f]			**$1,180+B**

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] Incidences are rounded to the nearest 100.
[c] The U_I are the incidences for the unquantified category i.
[d] Dollar values are rounded to the nearest 10.
[e] **B** is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_{17}$.
[f] These estimates are based on the EPA preferred approach for valuing reductions in premature mortality, the VSL approach. This approach and an alternative, age-adjusted approach – the VSLY approach – are discussed more fully in section 11.9.

Table 11-13.
Final Section 126 Rule "Representative Year" SO_2 Emissions Banking Scenario: 2007 Monetized Benefits Estimates for Alternative Premature Mortality Valuation Approaches (Billions of 1997 dollars)

Premature Mortality Valuation Approach	**PM Mortality Benefits**	**Total PM Benefits**
Value of statistical life (VSL) ($5.9 million per life saved)[a]	$1.1	$1.2 + **B**
Value of statistical life-years (VSLY) ($360,000 per life-year saved, which implies $3.6 million per life saved, based on the mean of 14 life-years saved)[a, b]	$0.6	$0.7 + **B**

[a] Premature mortality estimates are determined assuming a 5 year distributed lag, which applies 25 percent of the incidence in year 1 and 2, and then 16.7 percent of the incidence in years 3, 4, and 5.
[b] The VSLY estimate is calculated by amortizing the $5.9 million mean VSL estimate over the 35 years of life expectancy associated with subjects in the labor market studies used to obtain the VSL estimate. The resulting estimate, using a 5 percent discount rate, is $360,000 per life-year saved in 1997 dollars. This approach is discussed more fully in section 11.9 above.

Table 11-14.
Sensitivity Analysis: Estimated Annual Quantified and Monetized Benefits of the Final Section 126 Rule in 2007 for the "SO_2 Increasing" SO_2 Emissions Banking Scenario

Endpoint	Pollutant	Avoided Incidence[b] (cases/year)	Monetary Benefits[c] (millions 1997$)
Premature mortality[a,f] (adults, 30 and over)	PM	50	$290
Chronic asthma (adult males, 27 and over)	Ozone	U_2	B_2
Chronic bronchitis	PM	30	$10
Hospital Admissions from Respiratory Causes	Ozone and PM	$20+U_3$	$<\$1+B_3$
Hospital Admissions from Cardiovascular Causes	Ozone and PM	$10+U_4$	$<\$1+B_4$
Emergency Room Visits for Asthma	Ozone and PM	$10+U_5$	$<\$1+B_5$
Acute bronchitis (children, 8-12)	PM	100	<$1
Lower respiratory symptoms (LRS) (children, 7-14)	PM	1,100	<$1
Upper respiratory symptoms (URS) (asthmatic children, 9-11)	PM	1,200	<$1
Shortness of breath (African American asthmatics, 7-12)	PM	300	<$1
Work loss days (WLD) (adults, 18-65)	PM	9,000	$1
Minor restricted activity days (MRAD)/Acute respiratory symptoms	Ozone and PM	$48{,}200+U_7$	$\$2+B_7$
Decreased worker productivity	Ozone	—	B_8
Other health effects	PM and Ozone	U_1+U_9	B_1+B_9
Recreational (Class I Area) visibility	PM and Gases	—	$20
Residential visibility	PM and Gases	—	B_{10}
Household soiling damage	PM	—	B_{11}
Materials damage	PM	—	B_{12}
Nitrogen Deposition	Nitrogen	—	B_{13}
Agricultural crop damage	Ozone	—	B_{15}
Commercial forest damage	Ozone	—	B_{16}
Other welfare effects	Ozone and PM	—	$B_{14}+B_{17}$
Monetized Total[f]			**$330+B**

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] Incidences are rounded to the nearest 100.
[c] The U_i are the incidences for the unquantified category i.
[d] Dollar values are rounded to the nearest 10.
[e] **B** is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_{13}$.
[f] These estimates are based on the EPA preferred approach for valuing reductions in premature mortality, the VSL approach. Using an alternative, age-adjusted approach – the VSLY approach – monetized benefits of reductions in premature mortality are estimated to be $0.2 billion. Total monetized benefits using the VSLY approach are projected to be around $0.2 billion. These approaches are discussed more fully in section 11.9.

Table 11-15.
Sensitivity Analysis: Estimated Annual Quantified and Monetized Benefits of the Final Section 126 Rule in 2007 for the "SO_2 Decreasing" SO_2 Emissions Banking Scenario

Endpoint	Pollutant	Avoided Incidence[b] (cases/year)	Monetary Benefits[c] (millions 1997$)
Premature mortality[a,f] (adults, 30 and over)	PM2.5	340	$1,830
Chronic asthma (adult males, 27 and over)	Ozone	U_2	B_2
Chronic bronchitis	PM10	174	$55
Hospital Admissions from Respiratory Causes	Ozone and PM	$82 + U_3$	$\$1+B_3$
Hospital Admissions from Cardiovascular Causes	Ozone and PM	$38 + U_4$	$\$1+B_4$
Emergency Room Visits for Asthma	Ozone and PM	$66 + U_5$	$<\$1+B_5$
Acute bronchitis (children, 8-12)	PM	600	<$1
Lower respiratory symptoms (LRS) (children, 7-14)	PM	6,700	<$1
Upper respiratory symptoms (URS) (asthmatic children, 9-11)	PM	6,124	<$1
Shortness of breath (African American asthmatics, 7-12)	PM	1,207	<$1
Work loss days (WLD) (adults, 18-65)	PM	61,500	$6
Minor restricted activity days (MRAD)/Acute respiratory symptoms	Ozone and PM	$265{,}200+U_7$	$\$13+B_7$
Decreased worker productivity	Ozone	—	B_8
Other health effects	PM and Ozone	U_1+U_9	B_1+B_9
Recreational (Class I Area) visibility	PM and Gases	—	$40
Residential visibility	PM and Gases	—	B_{10}
Household soiling damage	PM	—	B_{11}
Materials damage	PM	—	B_{12}
Nitrogen Deposition	Nitrogen	—	B_{13}
Agricultural crop damage	Ozone	—	B_{15}
Commercial forest damage	Ozone	—	B_{16}
Other welfare effects	Ozone and PM	—	$B_{14}+B_{17}$
Monetized Total[f]			**1,940+B**

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] Incidences are rounded to the nearest 100.
[c] The U_I are the incidences for the unquantified category i.
[d] Dollar values are rounded to the nearest 10.
[e] **B** is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_{13}$.
[f] These estimates are based on the EPA preferred approach for valuing reductions in premature mortality, the VSL approach. Using an alternative, age-adjusted approach – the VSLY approach – monetized benefits of reductions in premature mortality are estimated to be $0.9 billion. Total monetized benefits using the VSLY approach are projected to be around $1.0 billion. These approaches are discussed more fully in section 11.9.

In addition to the primary estimate, in Table 11-16 we present alternative calculations for the "Representative Year" scenario showing how the value for individual endpoints or total benefits would change if we were to make a different assumption about an element of the benefits analysis. For example, this table can be used to answer questions like "What would total benefits be if we were to use the Dockery, et al. C-R function to estimate avoided premature mortality?" This table provides alternative calculations both for valuation issues (e.g., the correct value for a statistical life saved) and for physical effects issues (e.g., how reversals in chronic illnesses are treated). This table is not meant to be comprehensive. Rather, it reflects some of the key issues identified by EPA or commentors as likely to have a significant impact on total benefits. Accompanying Table 11-16 is a brief discussion of each of the alternative calculations. Details are provided in the benefits TSD for this RIA (Abt Associates, 1999).

While Table 11-16 provides alternative calculations for specific alternative assumptions, there are some parameters to which total benefits may be sensitive but for which no or limited credible scientific information exists to determine plausible values. Sensitivity analyses for these parameters are presented in Appendix A. Issues examined in this appendix include alternative specifications for the lag structure of PM related premature mortality and impacts of assumed thresholds on the estimated incidence of avoided premature mortality. Also, this appendix contains several illustrative endpoint calculations for which the scientific uncertainty is too great to provide a reasonable estimate for which inclusion would lead to double-counting of benefits. These include premature mortality associated with daily fluctuations in PM, infant mortality associated with PM, and premature mortality associated with daily fluctuations in ozone.

We have simulated a distribution around our primary estimate to characterize uncertainty in the total benefit estimate due to measurement uncertainty, holding all other potentially uncertain inputs constant. Based on the simulated distribution, we have included calculations of the 5^{th} and 95^{th} percentiles of the distribution of benefits in Table 11-16. This provides an estimate of how sensitive the primary estimate of total benefits would be to measurement errors if all other factors could be treated as certain. However, these do not represent the overall potential range of benefits, given the large number of uncertain factors for which we are not able to provide uncertainty estimates. In most cases the effect of the uncertainty on total benefits is unknown (i.e., it could increase or decrease benefits depending on specific conditions). Section 11.6 of this chapter provides a discussion of how we account for uncertainty in this benefits analysis.

Table 11-16.
Alternative Benefits Calculations for the 2007 "Representative Year" Scenario

Alternative Calculation	Description of Estimate	Impact on Total Monetized Benefits (million 1997$)
5th percentile of "measurement" uncertainty distribution	Estimate of total monetized benefits at the 5th percentile of a distribution generated using Monte Carlo simulation assuming measurement error is the only source of uncertainty in the primary benefits estimates.	-$950 (-81%)
95th percentile of "measurement" uncertainty distribution	Estimate of total monetized benefits at the 95th percentile of a distribution generated using Monte Carlo simulation assuming measurement error is the only source of uncertainty in the primary benefits estimates.	+$1,510 (+128%)
PM-related premature mortality based on the Dockery et al. study	The Dockery et al. study provides an alternative estimate of the relationship between chronic PM exposure and mortality. The number of avoided mortality incidences increases from 200 to 460 (230%).	+$1,420 (+120%)
Value of avoided premature mortality incidences based on statistical life years.	Calculate the incremental number of life-years lost from exposure to changes in ambient PM and use the value of a statistical life year based on a $5.9 million value of a statistical life.	-$530 (-45%)
Reversals in chronic bronchitis treated as lowest severity cases	Instead of omitting those cases of chronic bronchitis that reverse after a period of time, they are treated as being cases with the lowest severity rating. The number of avoided chronic bronchitis incidences increases from 100 to 190 (90%).	+$10 (+1%)
Value of visibility changes in Eastern U.S. residential areas	Value of visibility changes outside of Class I areas are estimated for the Eastern U.S. based on the reported values for Chicago and Atlanta derived from McClelland, et al. (1990).	+$60 (+5%)
Household soiling damage	Value of decreases in expenditures on cleaning are estimated using values derived from Manuel et al. (1983).	+$5 (+<1%)
Avoided costs of reducing nitrogen loadings in east coast estuaries	Estuarine benefits in 12 east coast estuaries from reduced atmospheric nitrogen deposition are approximated using the avoided costs of removing or preventing loadings from terrestrial sources.	+$90 (+8%)

The 5th and 95th percentile alternative calculations (rows 1 and 2 of Table 11-16) are estimated by holding air quality changes, population estimates, and other factors constant and determining the distribution of total benefits that would be generated by a large number of random draws from the distributions of C-R functions and economic valuation functions. These alternative calculations thus show how the primary estimate of benefits changes in response to uncertainty in the measurement of C-R and valuation functions.

The Dockery et al. estimate of the relationship between PM exposure and premature mortality (row 3 of Table 11-16) is a plausible alternative to the Pope et al estimate. The SAB has noted that "the [Dockery et al.] study had better monitoring with less measurement error than did most other studies" (EPA-SAB-COUNCIL-ADV-99-012, 1999). However, the Dockery et al. study had a more limited geographic scope (and a smaller study population) than the Pope et al. study. The demographics of the population in the Pope et al. study, i.e. largely white and middle-class, may also produce a downward bias in their PM mortality coefficient, because short-term studies indicate that the effects of PM tend to be significantly greater among groups of lower socioeconomic status. The Dockery et al. study also covered a broader age category (25 and older compared to 30 and older in the Pope study) and followed the cohort for a longer period (15 years compared to 8 years in the Pope et al. study). For these reasons, the Dockery et al. study is considered to be a plausible alternative estimate of the avoided premature mortality incidences associated with the final Section 126 rule.

The value of statistical life years alternative calculation (row 4 of Table 11-16) recognizes that individuals who die from air pollution related causes tend to be older than the average age of individuals in the VSL studies used to develop the $5.9 million value.

The treatment of reversals in chronic bronchitis incidences is addressed in row 5 of Table 11-16. Reversals are defined as those cases in which an individual reported having chronic bronchitis at the beginning of the study period but reported not having chronic bronchitis in follow-up interviews at a later point in the study period. Since, by definition, chronic diseases are long-lasting or permanent, it is not chronic if the disease goes away. However, we have not captured the benefits of reducing incidences of bronchitis that are somewhere in-between acute and chronic. One way to address this is to treat reversals as cases of chronic bronchitis that are at the lowest severity level. These cases thus get the lowest value for chronic bronchitis. This provides a reasonable alternative to the zero value assigned to these reversals in the primary estimate.

The alternative calculation for residential visibility (row 6 of Table 11-16) is based on the McClelland, et al. study of WTP for visibility changes in Chicago and Atlanta. As discussed in Section 11.8.1, the residential visibility estimates from the available literature have been determined by the SAB to be inadequate for use in a primary estimate in a benefit-cost analysis. However, EPA recognizes that residential visibility is likely to have some value and the McClelland, et al. estimates are the most useful in providing an estimate of the likely magnitude of the benefits of residential visibility improvements.

The alternative calculation for household soiling (row 7 of Table 11-16) is based on the Manuel, et al. study of consumer expenditures on cleaning and household maintenance. This study has been cited as "the only study that measures welfare benefits in a manner consistent with economic principals" (Desvouges, et al., 1998). However, the data used to estimate household soiling damages in the Manuel, et al. study is from a 1972 consumer expenditure survey and as such may not accurately represent consumer preferences in 2007. EPA recognizes this limitation, but believes the Manuel et al. estimates are still a useful indicator of the likely magnitude of the benefits of reduced household soiling by PM.

The alternative calculation for the avoided costs of reductions in nitrogen loadings (row 8 of Table 11-16) is constructed by examining the avoided costs to surrounding communities of reduced nitrogen loadings for three case study estuaries (U.S. EPA, 1998).[22] The three case study estuaries are chosen because they have agreed upon nitrogen reduction goals and the necessary nitrogen control cost data have been collected for these estuaries. The values of atmospheric nitrogen reductions are determined on the basis of avoided costs associated with agreed upon controls of nonpoint water pollution sources. Benefits are estimated using a weighted-average, locally-based cost for nitrogen removal from water pollution (U.S. EPA, 1998a). Valuation reflects water pollution control cost avoidance based on the weighted average cost/pound of current non-point source water pollution controls for nitrogen in the three case study estuaries. Taking the weighted cost/pound of these available controls assumes States will combine low cost and high cost controls, which could inflate avoided cost estimates. The details of the nitrogen deposition benefits calculation are provided in the benefits TSD for this RIA (Abt Associates, 1999). The avoided cost measure is likely to be an underestimate of the value of reduced nitrogen loadings in eastern estuaries because: 1) the twelve estuaries represent only about fifty percent of the total watershed area in the eastern U.S.; and 2) costs avoided are not good proxies for willingness-to-pay.

[22] The case study estuaries are Albemarle-Pamlico Sounds, Chesapeake Bay, and Tampa Bay.

11.10 References

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Chapter 12. BENEFIT-COST COMPARISON

12.1 Summary of Costs and Benefits

This Regulatory Impact Analysis (RIA) provides cost, economic impact, and benefit estimates that are potentially useful for evaluating the efficiency of the Section 126 rulemaking. Benefit-cost analysis provides a systematic framework for assessing and comparing such alternatives. According to economic theory, the efficient alternative maximizes net benefits to society (i.e., social benefits minus social costs). However, there are practical limitations for the comparison of benefits to costs in this analysis. This chapter also discusses the key limitations and uncertainties associated with the benefit and cost estimates. Nonetheless, if one is mindful of these limitations, the relative magnitude of the benefit-cost comparison presented here can be useful information.

The estimated cost of implementing the Section 126 rule is **$1.1 billion (1997$)** for the selected regulatory alternative consisting of a 0.15 lb/mmBtu NOx emission limit for electricity generating units and 60% NOx emission control for large industrial boilers and combustion turbines. This estimate includes monitoring and administrative costs, including those associated with the trading program.

As discussed in Chapter 11, time constraints prevented us from conducting a complete benefits analysis characterizing both ozone and PM-related benefits. We were able to model expected changes in ambient PM concentrations, but were not able to model changes in ambient ozone concentrations. Air quality based estimates of ozone-related benefits will be presented in a supplemental volume to this RIA. However, to provide a more accurate comparison with costs, we construct a projected ozone benefits estimate by applying a dollar per ton ($/ton) benefit transfer value based on the NOx SIP call ozone benefits analysis. To construct this estimate, we performed the following steps:

1) Adjusted the ozone benefits estimated for the NOx SIP call to reflect the current set of endpoints and benefits assumptions and updated the base year to 1997 dollars.

2) Divided the resulting estimate by the total tons of NOx reduced under the NOx SIP call to obtain monetary ozone benefits per ton ($/ton) of NOx reduced.

3) Multiplied the $/ton value by the amount of NOx reductions for the final Section 126 rule.

These calculations for this benefits transfer exercise are laid out in Table 12-1. The projected estimate of ozone-related benefits from implementing the Section 126 rule is **$0.2 billion (1997$)** for the selected regulatory alternatives for EGUs and non-EGUs. Actual ozone-related benefits may be greater or less than this projection, depending on the actual changes in ozone and the geographic distribution of those changes.

Table 12-1.
Estimation of Ozone $/ton Transfer Values for NOx Reductions Using Estimates from the NOx SIP call

	Description	Outcome
Step 1a	Calculate unadjusted ozone benefits from NOx SIP Call "Best Estimate" (Hubbell, 1998)	$2,180 million (1997$)
Step 1b	Adjusted ozone benefits (applying SAB recommended current assumptions and endpoint sets[a])	$380 million (1997$)
Step 2	Divide adjusted ozone benefits by total NOx reductions for the NOx SIP call	$380 million/1.1 million tons = $345/ton (1997$)
Step 3	Multiply $/ton by total NOx reductions for the final Section 126 rule	$345/ton * 0.66 million tons = $230 million (1997$)

[a] Chronic asthma has been added as an endpoint in the Section 126 benefits analysis. However, this endpoint was not estimated for the NOx SIP call. As a result, all else being equal, the $/ton value presented here will tend to underestimate total ozone benefits per ton.

As explained in more detail in Chapters 9 and 10, selection of 2007 as the analytical year for the benefits analysis resulted in SO_2 emissions and air quality results that are not representative of the expected change in air quality for most years when the rule is in effect. Because of the SO_2 emissions banking provisions of the acid rain permit program, SO_2 emissions can increase in some years and decrease in others as long as net SO_2 emissions do not change over a specified time horizon. The 2007 analytical year is a year when there are particularly high levels of permit withdrawals (due to shifting in electricity generation and adoption of technologies that use high sulfur coal), such that SO_2 emissions in 2007 increase relative to baseline levels. In most other years, SO_2 emissions decrease, so 2007 represents a "worst case" year with respect to the change in SO_2 emissions. To account for this, we have constructed a "Representative Year" (in terms of SO_2 emissions) scenario by zeroing out all changes in sulfates, both positive and negative, in calculating the changes in $PM_{2.5}$. Changes in $PM_{2.5}$ are then driven solely by changes in nitrate concentrations. EPA believes that this "Representative Year" scenario is a closer approximation to the expected annual benefits of the Section 126 rule[1].

EPA's preferred estimate of PM-related benefits of implementing the Section 126 rule is **$1.2 billion (1997$)** for the selected regulatory alternatives for EGUs and non-EGUs. This

[1] Estimated benefits for two alternative scenarios, a 2007 "SO_2 increasing" scenario and a 2004 "SO_2 decreasing" scenario, are presented in Chapter 11. However, EPA believes that the most representative benefits estimate is provided by the "Representative Year" scenario presented in this chapter.

estimate does not include the monetary value of several known PM-related welfare effects, including residential visibility, household soiling and materials damage, and deposition of nitrogen to sensitive estuaries. Detailed estimates of the benefits for individual PM-related health and welfare endpoints are provided in Chapter 11.

Using EPA's preferred approach for monetizing reductions in PM-related premature mortality – the VSL approach – total monetized benefits (ozone plus PM) of the final Section 126 rule are projected to be around **$1.4 billion (1997$).** Any comparison of benefits and costs for this rule will provide limited information, given the incomplete estimate of benefits. However, even with the limited set of benefit categories we were able to monetize, monetized net benefits using EPA's preferred method for valuing avoided incidences of premature mortality are approximately **$0.3 billion (1997$).** Using the alternative, age-adjusted approach – the VSLY approach – total monetized benefits are projected to be around **$0.9 billion (1997$)**. Monetized net benefits using this approach are approximately **$-0.3 billion (1997$)**. Costs, benefits, and net benefits for the two alternative valuation methods are summarized in Tables 12-2 and 12-3.

As with any estimate based on a complex, multi-stage model, there are numerous sources of uncertainty that can affect the confidence in the estimates of benefits. These uncertainties are discussed in the individual chapters on emissions (Chapter 9), air quality (Chapter 10), and benefits (Chapter 11).

Table 12-2
2007 "Representative Year" Estimated Annual Monetized Costs, Benefits, and Net Benefits for the Section 126 Rule[a]: EPA Preferred Estimates Using the Value of Statistical Lives Saved Approach to Value Reductions in Premature Mortality

	Million 1997$
Compliance costs	$1,200
Monetized PM-related benefits[b,c]	$1,200
Projected Monetized Ozone-related benefits[b]	$200
Projected Monetized net benefits[c]	$200

[a] For this chapter, all costs and benefits are rounded to the nearest 100 million. Thus, figures presented in this chapter may not exactly equal benefit and cost numbers presented in earlier chapters.
[b] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 11-1 in Chapter 11 of this RIA.
[c] These estimates are based on the EPA preferred approach for valuing reductions in premature mortality, the VSL approach. This approach and an alternative, age-adjusted approach – the VSLY approach – are discussed more fully in section 11.9 of Chapter 11.

Table 12-3
2007 "Representative Year" Estimated Annual Monetized Costs, Benefits, and Net Benefits for the Section 126 Rule[a]: EPA Preferred Estimates Using the Value of Statistical Life Years Saved Approach to Value Reductions in Premature Mortality

	Million 1997$
Compliance costs	$1,200
Monetized PM-related benefits[b,c]	$700
Projected Monetized Ozone-related benefits[b]	$200
Projected Monetized net benefits[c]	$-300

[a] For this chapter, all costs and benefits are rounded to the nearest 100 million. Thus, figures presented in this chapter may not exactly equal benefit and cost numbers presented in earlier chapters.
[b] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 11-1 in Chapter 11 of this RIA.
[c] The VSLY estimate is calculated by amortizing the $5.9 million mean VSL estimate over the 35 years of life expectancy associated with subjects in the labor market studies used to obtain the VSL estimate. The resulting estimate, using a 5 percent discount rate, is $360,000 per life-year saved in 1997 dollars. This approach is discussed more fully in section 11.9 of Chapter 11.

In addition to the monetized benefits listed in Table 12-2, the final Section 126 rule will result in significant improvements in visibility in urban and suburban residential areas, and reductions in loadings of nitrogen to sensitivity estuaries, helping state and local governments reach target reduction goals for important estuaries including the Chesapeake Bay, the Albemarle-Pamlico Sound, and Long Island Sound. The final Section 126 rule will help reduce loadings in these estuaries by up to 22 percent of stated reduction goals.

12.2 Findings and Qualifications

Cost-benefit analysis provides a valuable framework for organizing and evaluating information on the effects of environmental programs. When used properly, cost-benefit analysis helps illuminate important potential effects of alternative policies and helps set priorities for closing information gaps and reducing uncertainty. However, not all relevant costs and benefits can be captured in any analysis. Executive Order 12866 clearly indicates that unquantifiable or nonmonetizable categories of both costs and benefits should not be ignored. There are many important unquantified and unmonetized costs and benefits associated with reductions in NOx emissions, including many health and welfare effects. Potential benefit categories that have not been quantified and monetized are listed in Chapter 11, Table 11-1 of this volume.

Several specific limitations deserve to be mentioned:

- The state of atmospheric modeling is not sufficiently advanced to provide a workable "one atmosphere" model capable of characterizing ground-level pollutant exposure for all pollutants of interest (e.g., ozone, particulate matter, carbon monoxide, nitrogen deposition, etc). Therefore, the Environmental Protection Agency (EPA) must employ several different pollutant models to characterize the effects of alternative policies on relevant pollutants. Also, not all atmospheric models have been widely validated against actual ambient data. In particular, since a broad-scale monitoring network does not yet exist for fine particulate matter ($PM_{2.5}$), atmospheric models designed to capture the effects of alternative policies on $PM_{2.5}$ are not fully validated. Additionally, significant shortcomings exist in the data that are available to perform these analyses. While containing identifiable shortcomings and uncertainties, EPA believes the models and assumptions used in the analysis are reasonable based on the available evidence.

- Another dimension adding to the uncertainty of this analysis is time. In the case of air pollution control, 15 years is a very long time over which to carry assumptions. Pollution control technology has advanced considerably in the last 10 years and can be expected to continue to advance in the future. Yet there is no clear way to model this advance for use in this analysis. In addition, there is no clear way to predict future meteorological conditions, or the growth in source-level emissions over time. Again, EPA believes that the assumptions to capture these elements are reasonable based on the available evidence.

- Qualitative and more detailed discussions of the above and other uncertainties and limitations are included in the RIA. Where information and data exist, quantitative characterizations of these uncertainties are included. However, data limitations prevent an overall quantitative estimate of the uncertainty associated with final estimates. Nevertheless, the reader should keep all of these uncertainties and limitations in mind when reviewing and interpreting the results.

12.3 References

Hubbell, B. 1998. Memorandum to the Files. Preliminary Estimates of Benefits of the NOx SIP Call. October.

Appendix A.
Supplementary Benefit Estimates and Sensitivity Analyses of Key Parameters in the Benefits Analysis

A.1 Introduction and Overview

In chapter 11, we presented our primary estimate of the monetized benefits of the final Section 126 rule. This primary estimate is based on the best available scientific literature and methods. In addition, we presented a series of alternative calculations (see Table 11-15) representing plausible alternative assumptions about some key parameters in the analysis. In addition to the alternative calculations presented in Table 11-15, there are two other categories of estimates which we provide in this appendix: supplemental calculations and sensitivity analyses. Supplemental calculations are intended to provide additional information about specific health effects, but are not suitable for inclusion in the primary or alternative estimates due to concerns about double-counting of benefits or the high degree of uncertainty about the estimates. Sensitivity analyses are intended to provide additional information about those key parameters for which we have no defensible scientific literature from which particular values could be drawn for the purposes of an alternative calculation.

In chapter 11, we estimated the benefits of the final Section 126 analysis using the most comprehensive set of endpoints available. For some health endpoints, this meant using a dose-response function that linked a larger set of effects to a change in pollution, rather than using dose-response functions for individual effects. For example, the minor restricted activity days/any of 19 acute respiratory symptoms endpoint covers most of the symptoms used to characterize asthma attacks and days of moderate or worse asthma. For premature mortality, we selected a dose-response function that captured reductions in incidences due to both long and short-term exposures to ambient concentrations of particulate matter (PM). In addition, the premature mortality dose-response function is expected to capture at least some of the mortality effects associated with exposure to ozone. This effect is described more fully below in section A.2.

In order to provide the reader with a fuller understanding of the health effects associated with reductions in air pollution associated with the final Section 126 rule, this appendix provides estimates for those health effects which, if included in the primary estimate, could result in double-counting of benefits. For some endpoints, such as ozone mortality, additional research is needed to provide separate estimates of the effects for different pollutants, i.e. PM and ozone. These supplemental estimates should not be considered as additive to the primary estimate of benefits. Supplemental estimates included in this appendix include premature mortality associated with short-term exposures to PM and ozone, asthma attacks, and occurrences of moderate or worse asthma symptoms. In addition, an estimate of the avoided incidences of premature mortality in infants is provided. Because the Pope, et al. estimate applies only to adults, avoided incidences of infant mortality are additive to the primary benefits estimate.

Table 11-15 in Chapter 11 reports the results of alternative calculations based on plausible alternatives to the assumptions used in deriving the primary estimate of benefits. In addition to these calculations, two important parameters, the length and structure of the potential lag in mortality effects and thresholds in PM health effects, have been identified as key to the analysis, and are explored in this appendix through the use of sensitivity analyses.

A.2 Supplemental Benefit Estimates

In the primary estimate, we use the Pope et al. study to provide the concentration-response (C-R) function relating premature mortality to long-term PM exposure. In the primary analysis, we assume that this mortality occurs over a five year period, with 25 percent of the deaths occurring in the first year, 25 percent in the second year, and 16.7 percent in each of the third, fourth, and fifth years. Studies examining the relationship between short-term exposures and premature mortality can reveal what proportion of premature mortality is due to immediate response to daily variations in PM. There is only one short-term study (presenting results from 6 separate U.S. cities) that uses $PM_{2.5}$ as the metric of PM (Schwartz et al., 1996). As such, the supplemental estimate for premature mortality related to short-term PM exposures is based on the pooled city-specific, short-term $PM_{2.5}$ results from Schwartz, et al.

In the Proposed Section 126/Final NOx SIP Call RIA, we estimated avoided incidences of ozone-related premature mortality for the primary benefits estimate. Based on recent advice from the Science Advisory Board (SAB) (EPA-SAB-Council-ADV-99-012, 1999), we have converted this endpoint to a supplemental estimate to avoid potential double-counting of benefits captured by the Pope, et al. PM premature mortality endpoint[1]. There are many studies of the relationship between ambient ozone levels and daily mortality levels. The supplemental estimate is calculated using results from only four U.S. studies (Ito and Thurston, 1996; Kinney et al., 1995; Moolgavkar et al., 1995; and Samet et al., 1997), based on the assumption that demographic and environmental conditions on average would be more similar between these studies and the conditions prevailing when the Section 126 rule is implemented. However, the full body of peer-reviewed ozone mortality studies should be considered when evaluating the weight of evidence

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[1]While the growing body of epidemiological studies suggests that there may be a positive relationship between ozone and premature mortality, there is still substantial uncertainty about this relationship. Because the evidence linking premature mortality and particulate matter is currently stronger than the evidence linking premature mortality and ozone, it is important that models of the relationship between ozone and mortality include a measure of particulate matter as well. Because of the lack of monitoring data on fine particulates or its components, however, the measure of particulate matter used in most studies was generally either PM10 or TSP or, in some cases, Black Smoke. If a component of PM, such as PM or sulfates, is more highly correlated with ozone than with PM or TSP, and if this component is also related to premature mortality, then the apparent ozone effects on mortality could be at least partially spurious. Even if there is a true relationship between ozone and premature mortality, after taking particulate matter into account, there would be a potential problem of double counting in this analysis if the ozone effects on premature mortality were added to the PM effects estimated by Pope et al., 1995, because, as noted above, the Pope study does not include ozone in its model.

regarding the presence of an association between ambient ozone concentrations and premature mortality. We combined these studies using probabilistic sampling methods to estimate the impact of ozone on mortality incidence. The technical support document for this analysis provides additional details of this approach (Abt Associates, 1999). The estimated incidences of short-term premature mortality are valued using the value of statistical lives saved method, as described in Chapter 11.

The estimated effect of PM exposure on premature mortality in infants (post neo-natal) is based on a single U.S. study (Woodruff, et al, 1997) which, on recommendation of the SAB, was deemed too uncertain to include in the primary analysis. Adding this endpoint to the primary benefits estimate would result in an increase in total benefits.

As noted in Chapter 11, asthma affects over seven percent of the U.S. population. One study identifies a statistical association between air pollution and the development of asthma in some non-smoking adult men. Other studies identify a relationship between air quality and occurrences of acute asthma attacks or worsening of asthma symptoms. Supplemental estimates are provided for two asthma related endpoints. Occurrence of moderate or worse asthma symptoms in adults is estimated using a C-R function derived from Ostro, et al. (1991). Asthma attacks in children are estimated using a C-R function derived from Whittemore and Korn (1980). Both asthma attacks and occurrence of moderate or worse asthma symptoms are valued at $39 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986), a study which surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects.

Table A-1 presents estimated incidences and values for the supplemental endpoints listed above. These estimates are based on the "Representative Year" SO_2 emissions banking scenario described in Chapters 9 and 11. Because of time constraints, we are unable to provide a supplemental estimate for premature mortality associated with short-term exposures to ozone. A supplemental volume to be published in January of 2000 will contain estimates of ozone-related benefits.

Table A-1.
Supplemental Benefit Estimates for the Final Section 126 Rule for the 2007 "Representative Year" SO2 Banking Emissions Scenario

Endpoint	*Pollutant*	*Avoided Incidence[a] (cases/year)*	*Monetary Benefits[b] (millions 1997$)*
Premature mortality (short-term exposures to PM)	PM	50	$290
Premature mortality (short-term exposures to ozone)[c]	Ozone	??	??
Premature mortality in infant population	PM	<1	$3
Asthma attacks	PM	3,500	$<1
Asthma attacks [c]	Ozone	??	??
Moderate or Worse Asthma	PM	3,800	$<1

[a] Incidences are rounded to the nearest 100.
[b] Dollar values are rounded to the nearest 10.
[c] Due to time constraints on ozone modeling, ozone-related health effects could not be provided for this RIA. Ozone results will be available in a supplementary volume in January, 2000.

The supplemental estimate of 50 avoided incidences of premature mortality from short-term exposures to PM is exactly 25 percent of the total avoided premature mortality incidences estimated using the Pope, et al., study (200 incidences). This lends support for the assumption that 25 percent of the premature deaths predicted to be avoided in the first year using the Pope study should be assigned to the first year after a reduction in exposure.

The infant mortality estimate indicates that exclusion of this endpoint does not have a large impact, either in terms of incidences or monetary value. Estimates of the value for separate asthma endpoints are well under the estimate of the value of all respiratory symptoms. All of these supplemental estimates support the set of endpoints and assumptions chosen as the basis of the primary benefits estimate described in Chapter 11.

A.3 Sensitivity Analyses

As discussed in Chapter 11, there are two key parameters of the benefits analysis for which there are no specific values recommended in the scientific literature. These parameters, the lag between changes in exposure to PM and reductions in premature mortality and the threshold in PM-related health effects, are investigated in this section through the use of sensitivity analyses, We perform an analysis of the sensitivity of benefits valuation to the lag structure by considering a range of assumptions about the timing of premature mortality. To examine the threshold parameter, we show how the estimated avoided incidences of PM-related premature mortality are distributed with respect to the threshold.

A.3.1 Alternative Lag Structures

As noted by the SAB (EPA-SAB-COUNCIL-ADV-00-001, 1999), "some of the mortality effects of cumulative exposures will occur over short periods of time in individuals with compromised health status, but other effects are likely to occur among individuals who, at baseline, have reasonably good health that will deteriorate because of continued exposure. No animal models have yet been developed to quantify these cumulative effects, nor are there epidemiologic studies bearing on this question." However, they also note that "Although there is substantial evidence that a portion of the mortality effect of PM is manifest within a short period of time, i.e., less than one year, it can be argued that, if no a lag assumption is made, the entire mortality excess observed in the cohort studies will be analyzed as immediate effects, and this will result in an overestimate of the health benefits of improved air quality. Thus some time lag is appropriate for distributing the cumulative mortality effect of PM in the population." In the primary analysis, based on SAB advice, we assume that mortality occurs over a five year period, with 25 percent of the deaths occurring in the first year, 25 percent in the second year, and 16.7 percent in each of the third, fourth, and fifth years. Readers should note that the selection of a 5 year lag is not supported by any scientific literature on PM-related mortality. Rather it is intended to be a best guess at the appropriate distribution of avoided incidences of PM-related mortality.

Although the SAB recommended the five-year distributed lag be used for the primary analysis, the SAB has also recommended (EPA-SAB-COUNCIL-ADV-00-001, 1999) that alternative lag structures be explored as a sensitivity analysis. Specifically, they recommended an analysis of 0, 8, and 15 year lags. The 0 year lag is representative of EPA's assumption in previous RIAs. The 8 and 15 year lags are based on the length of the study periods from the Pope and Dockery studies, respectively[2]. However, neither the Pope or Dockery studies assumed any lag structure when estimating the relative risks from PM exposure. In fact, the Pope and Dockery studies do not contain any data either supporting or refuting the existence of a lag. Therefore, any lag structure applied to the avoided incidences estimated from either of these studies will be an assumed structure. The 8 and 15 year lags implicitly assume that all premature mortalities occur at the end of the study periods, i.e. at 8 and 15 years. We also present two additional lags: a 15 year distributed lag with the distribution skewed towards the early years and a 15 year distributed lag with the distribution skewed towards the later years. This is to demonstrate how sensitive the results are not only to the length of the lag, but also to the shape of the distribution of incidences over the lag period. It is important to keep in mind that changes in the lag assumptions do not change the total number of estimated deaths, but rather the timing of those deaths.

The estimated impacts of alternative lag structures on the monetary benefits associated

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[2]Although these studies were conducted for 8 and 15 years, respectively, it is not likely that the authors determined the length of the study period based on any hypothesis about a lag in effects. It is more likely that the duration of the studies was tied to the expense of conducting long-term studies or the amount of satisfactory data that would be necessary to develop a C-R function.

with reductions in PM-related premature mortality (estimated with the Pope, et al. C-R function) are presented in Table A-2. These estimates are based on the value of statistical lives saved approach, i.e. $5.9 million per incidence, and assume a 5 percent discount rate over the lag period. The results using the primary 5-year lag are repeated here for comparison. The table reveals that the length of the lag period is not as important as the distribution of incidences within the lag period. A 15 year distributed lag with most of the incidences occurring in the early years reduces monetary benefits less than an 8 year lag with all incidences occurring at the eighth year. Even with an extreme lag assumption of 15 years, benefits are reduced by less than half relative to the no lag and primary (5 year distributed lag) benefit estimates.

Table A-2.
Sensitivity Analysis of Alternative Lag Structures for PM-related Premature Mortality

Lag	Description	Monetary Benefit (millions 1997$)	Percent of Primary Estimate
5-year distributed	Primary estimate, incidences are distributed with 25% in the 1st and 2nd years, and 16.7% in the remaining 3 years.	$1,094	100%
None	Incidences all occur in the first year	$1,188	109%
8 year	Incidences all occur in the 8th year	$844	77%
15 year	Incidences all occur in the 15th year	$600	55%
15 year distributed - skewed early	Incidences are distributed with 30% in the 1st year, 25% in the 2nd year, 15% in the 3rd year, 6% in the 4th year, 4% in the 5th year, and the remainder 20% distributed over the last 10 years.	$1,060	97%
15 year distributed - skewed late	Incidences are distributed with 4% in the 11th year, 6% in the 12th year, 15% in the 13th year, 25% in the 14th year, and 30% in the 15th year, with the remaining 20 % distributed over the first 10 years.	$691	63%

A.3.2 PM Health Effect Threshold

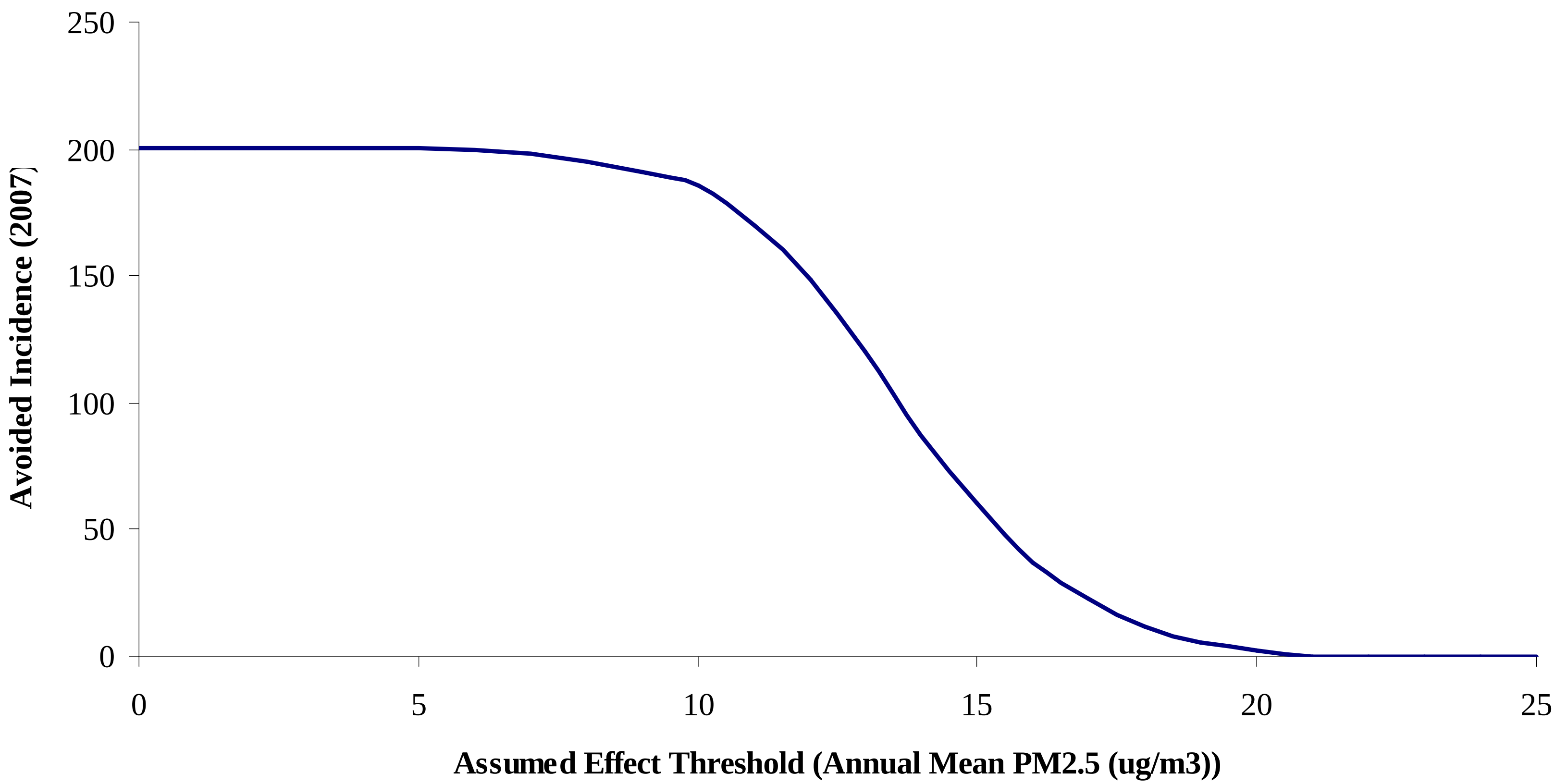
In developing its primary estimate of benefits for previous analyses, EPA has assumed a

PM health effects threshold equal to the lowest observed level in a given epidemiological study or anthropogenic background when no lowest observed level is reported (Hubbell, 1998). Commenters have suggested that EPA assume a threshold equal to the PM standard of 15 $\mu g/m^3$. Recent advice from the SAB (EPA-SAB-Council-ADV-99-012, 1999) is that there is currently no scientific basis for selecting a threshold of 15 $\mu g/m^3$ or any other specific threshold for the PM related health effects considered in this analysis. The most important health endpoint that would be impacted by a PM threshold is premature mortality, as measured by the Pope, et al. (1995) C-R function. Pope et al. did not explicitly include a threshold in their analysis. However, if the true mortality C-R relationship has a threshold, then Pope et al.'s slope coefficient would likely have been underestimated for that portion of the C-R relationship above the threshold. This would likely lead to an underestimate of the incidences of avoided cases above any assumed threshold level. It is difficult to determine the size of the underestimate without data on a likely threshold and without re-analyzing the Pope et al. data. Nevertheless, it is illustrative to show at what threshold levels benefits are significantly affected.

Any of the PM-related health effects estimated in the primary analysis could have a threshold; however a threshold for PM-related mortality would have the greatest impact on the overall benefits analysis. Figure A-1 shows the effect of incorporating a range of possible thresholds, using 2007 PM levels and the Pope et al. (1995) study.

The distribution of premature mortality incidences in Figure A-1 indicates that over ninety percent of the premature mortality related benefits of the final Section 126 rule are due to changes in PM concentrations occurring above 10 $\mu g/m^3$, and around seventy-five percent are due to changes above 12 $\mu g/m^3$, the lowest observed level in the Pope, et al. study. Around thirty percent of avoided incidences are due to changes occurring above the $PM_{2.5}$ standard of 15 $\mu g/m^3$.

Figure A-1.
Impact of PM Health Effects Threshold on Avoided Incidences of Premature Mortality Estimated with the Pope Concentration-Response Function



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Appendix B.
Partial States Analysis

B.1 Introduction and Overview

The analyses presented in this RIA reflect controls applied to all counties in the states named in the 8 petitions considered in the final Section 126 rule. Some of the counties in the named states are not specifically covered under the 8 petitions considered in the final Section 126 rule. We have conducted a sensitivity analysis of the PM-related benefits for the region containing all the States in the final Section 126 region (12 States + DC), but not certain counties in Indiana, Kentucky, Michigan, and New York not covered in the 8 petitions. This is identified in this appendix as the "partial states" case. This analysis is based on the 2007 "Representative Year" scenario described in Chapters 9 and 11[1].

This analysis presents estimates of costs, benefits, and net benefits for the "partial states" case. Economic impacts are not estimated for the "partial states" case. Because of time and resource constraints, we are unable to provide estimates of ozone-related benefits for the "partial states" benefits analysis. As such, the benefit estimates presented here will understate total benefits of the rule. The set of PM-related health and welfare effects quantified and monetized for the "partial states" benefits analysis is identical to that in Chapter 11. The reader is directed to Chapter 11 for a complete discussion of the literature and methods used in calculating the benefits estimates presented in this appendix.

B.2 Emissions and Costs

The total NOx emissions reductions in the 2007 ozone season for the "partial states" case under the final alternatives (0.15 trading - electricity generating units (EGUs), 60% control - non-electricity generating sources (non-EGUs)) are 511,000 tons. As shown in Table B-1, this estimate is 148,000 tons, or 22 percent, less than the estimate shown in Chapter 9 for the final alternatives applied to the final Section 126 region. There are 216 fewer units or sources affected

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[1] Selection of 2007 as the analytical year for the benefits analysis resulted in SO_2 emissions and air quality results that are not representative of the expected change in air quality for most years when the rule is in effect. Because of the SO_2 emissions banking provisions of the acid rain permit program, SO_2 emissions can increase in some years and decrease in others as long as net SO_2 emissions do not change over a specified time horizon. The 2007 analytical year is a year when there are particularly high levels of permit withdrawals (due to shifting in electricity generation and adoption of technologies that use high sulfur coal), such that SO_2 emissions in 2007 increase relative to baseline levels. In most other years, SO_2 emissions decrease, so 2007 represents a "worst case" year with respect to the change in SO_2 emissions. To account for this, we have constructed a "Representative Year" (in terms of SO_2 emissions) scenario by zeroing out all changes in sulfates, both positive and negative, in calculating the changes in $PM_{2.5}$. Changes in $PM_{2.5}$ are then driven solely by changes in nitrate concentrations. EPA believes that this "Representative Year" scenario is a closer approximation to the expected annual benefits of the Section 126 rule.

(152 fewer EGUs and 64 non-EGUs), or 17 percent, less than in the analysis for the final Section 126 region. The total annual cost of compliance in the 2007 ozone season for the "partial states" case is roughly **$1.0 billion (1997 dollars).** This estimate is $250 million less than the estimate for the final alternatives applied to the final Section 126 region. Economic impacts are not available for the partial states case.

Table B-1. Emission Reductions and Costs Under the Final Section 126 Alternatives For the "Partial States" Case Compared to Results for Final Section 126 Region[a]

Source Category	Annual Costs for "Partial States" Case (millions of 1997 dollars)	Annual Costs Difference from Results for Final Section 126 Region (millions of 1997 dollars)	Emission Reductions in 2007 Ozone Season for the "Partial States" Case (1,000 tons)	Difference in Emission Reductions in 2007 Ozone Season (1,000 tons) from Results for Final Section 126 Region
EGUs	$910.7	$221.8	480	131
Non-EGUs	71.7	25.5	31	17
Total	$982.4	$247.3	511	148

[a] Results for the Final Section 126 region in which all counties in the States covered by the eight petitions are mentioned in Chapter 9.

B.3 PM-related Health and Welfare Benefits

Estimated health and welfare benefits for the endpoints described in Chapter 11 are presented in Table B-2. Not all benefits could be quantified or monetized. Potential benefit categories that have not been quantified and monetized are listed in Table 11-1 in Chapter 11 of this RIA. Note that the values of endpoints known to be affected by ozone and/or PM that we are not able to monetize are assigned a placeholder value, e.g. B_1, B_2, etc. Unquantified physical effects are indicated by a U. The estimate of total benefits is thus the sum of the monetized benefits and a constant, **B**, equal to the sum of the unmonetized benefits, $B_1+B_2+...+B_n$.

Total monetized PM-related benefits for the "partial states" case analysis of the final Section 126 rule are projected to be around **$1.1 billion (1997$).** This is $100 million less than for the comparable PM-related benefits in the full states analysis. Any comparison of benefits and costs for this rule will provide limited information, given the incomplete estimate of benefits. However, even with the limited set of benefit categories we were able to monetize, monetized PM-related net benefits are approximately **$0.1 billion (1997$).** For the full states analysis, we were able to estimate ozone-related benefits; for the "partial states" analysis we did not have sufficient time to conduct a similar analysis. Including ozone-related endpoints for the "partial states" case would further increase our estimate of net benefits. Costs, benefits, and net benefits are summarized in Table B-3.

These results suggest that our primary analysis including all counties in states covered by the final Section 126 petitions provides a conservative estimate of the net benefits of the rule.

Table B-2.
"Partial States" Case Estimated Annual Quantified and Monetized Benefits of the Final Section 126 Rule in 2007 for the "Representative Year" SO_2 Emissions Banking Scenario

Endpoint	Pollutant	Avoided Incidence[b] (cases/year)	Monetary Benefits[c] (millions 1997$)
Premature mortality[a] (adults, 30 and over)	PM2.5	180	$1,000
Chronic asthma (adult males, 27 and over)	Ozone	U_2	B_2
Chronic bronchitis	PM10	90	$30
Hospital Admissions from Respiratory Causes	Ozone and PM	$50+U_3$	$<\$1+B_3$
Hospital Admissions from Cardiovascular Causes	Ozone and PM	$20+U_4$	$<\$1+B_4$
Emergency Room Visits for Asthma	Ozone and PM	$40+U_5$	$<\$1+B_5$
Acute bronchitis (children, 8-12)	PM	320	<$1
Lower respiratory symptoms (LRS) (children, 7-14)	PM	3,470	<$1
Upper respiratory symptoms (URS) (asthmatic children, 9-11)	PM	3,450	<$1
Shortness of breath (African American asthmatics, 7-12)	PM	850	<$1
Work loss days (WLD) (adults, 18-65)	PM	27,200	$3
Minor restricted activity days (MRAD)/Acute respiratory symptoms	Ozone and PM	$145{,}260+U_7$	$\$10+B_7$
Decreased worker productivity	Ozone	—	B_8
Other health effects	Ozone and PM	U_1+U_9	B_1+B_9
Recreational (Class I Area) visibility	PM and Gases	—	$30
Residential visibility	PM and Gases	—	B_{10}
Household soiling damage	PM	—	B_{11}
Materials damage	PM	—	B_{12}
Nitrogen Deposition	Nitrogen	—	B_{13}
Agricultural crop damage	Ozone	—	B_{15}
Commercial forest damage	Ozone	—	B_{16}
Other welfare effects	Ozone and PM	—	$B_{14}+B_{17}$
Monetized Total			**$1,080+B**

[a] Premature mortality associated with ozone is not separately included in this analysis. It is assumed that the Pope et al. C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] Incidences are rounded to the nearest 100.
[c] Dollar values are rounded to the nearest 10.
[d] **B** is equal to the sum of all unmonetized categories, i.e. $B_1+B_2+...+B_{17}$.

Table B-3
“Partial States” Case Estimated Annual Monetized Costs, Benefits, and Net Benefits for the Section 126 Rule in 2007 for the “Representative Year” SO_2 Emissions Banking Scenario[a]

	Million 1997$
Compliance costs	$1,000
Monetized PM-related benefits[b]	$1,100
Monetized PM-related net benefits	$100

[a] For this table, all costs and benefits are rounded to the nearest 100 million. Thus, figures presented in this chapter may not exactly equal benefit and cost numbers presented in earlier chapters.
[b] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 11-1 in Chapter 11 of this RIA.

APPENDIX C

State-By-State Ozone Season NOx Emissions For Electric Generating Units By Regulatory Alternative

This appendix contains the state-by-state emissions data used to generate the map figures in Chapter 6. The source for this data is ICF analysis using the latest version of the Integrated Planning Model.

Table C-1:

State-by-State Section 126 Rule Budgets: 0.25, 0.20, 0.15, and 0.12 Uniform Trading Options (1,000 ozone season tons)

State Name	**0.25**	**0.20**	**0.15**	**0.12**
District of Columbia	0.3	0.3	0.2	0.2
Delaware	7.2	5.7	4.3	3.4
Indiana	76.6	61.3	46.0	36.8
Kentucky	60.1	48.1	36.0	28.8
Maryland	24.2	19.4	14.5	11.6
Michigan	51.6	41.3	31.0	24.8
North Carolina	52.1	41.7	31.3	25.0
New Jersey	16.1	12.9	9.7	7.7
New York	49.0	39.2	29.4	23.5
Ohio	76.2	60.9	45.7	36.6
Pennsylvania	80.1	64.1	48.1	38.5
Virginia	28.5	22.8	17.1	13.7
West Virginia	44.4	35.5	26.6	21.3
Total*	566.3	453.1	339.8	271.8

Source: ICF Resources
*Total may not sum due to rounding.

Table C-2:

State-by-State Section 126 Emissions Analysis: Initial Base Case, 0.15 Budget, and 0.15 Option Results for 2007 (1,000 ozone season tons)

State Name	Initial Base Case	0.15 Budget	0.15 Policy
District of Columbia	0.0	0.2	0.0
Delaware	5.8	4.3	4.2
Indiana	136.3	46.0	44.3
Kentucky	107.8	36.0	34.4
Maryland	32.6	14.5	13.2
Michigan	85.5	31.0	34.4
North Carolina	84.8	31.3	34.4
New Jersey	18.1	9.7	8.1
New York	39.2	29.4	23.4
Ohio	161.5	45.7	45.5
Pennsylvania	122.9	48.1	47.1
Virginia	40.9	17.1	18.5
West Virginia	115.5	26.6	32.3
Total*	950.8	339.8	339.8

Source: ICF Resources.
*Total may not sum due to rounding.